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A MIDAMERICAN ENERGY HOLDINGS COMPANY

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Submitted via email and electronically to www.regulations.gov

Carl Daly
Director, Air Program
U.S. EPA, Region 8
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Re: Docket ID No. EPA-R08-OAR-2012-0026
Approval, Disapproval and Promulgation of Implementation Plans; State of Wyoming; Regional Haze State Implementation Plan; Federal Implementation Plan for Regional Haze" (78 Fed. Reg. 34,738 (June 10, 2013)

Dear Mr. Daly:

PacifiCorp submits these comments (including attachments and exhibits) in response to the U.S. Environmental Protection Agency's re-proposed action regarding the Wyoming Regional Haze State Implementation Plan ("RH SIP"). PacifiCorp appreciates the opportunity to offer these comments.

Sincerely,

Micheal G. Dunn
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1407 W. North Temple
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August 13, 2013
PacifiCorp's "Detailed Comments" regarding: "Approval, Disapproval and Promulgation of State Implementation Plans; State of Wyoming; Regional Haze State Implementation Plan; Federal Implementation Plan for Regional Haze"

PacifiCorp submits these comments concerning EPA's proposed partial approval and partial disapproval of the Wyoming State Implementation Plan for Regional Haze ("Wyoming RH SIP"), as well as EPA's proposed Federal Implementation Plan ("RH FIP") for Wyoming. (*See* "Approval, Disapproval and Promulgation of Implementation Plans; State of Wyoming; Regional Haze State Implementation Plan; Federal Implementation Plan for Regional Haze," 78 Fed. Reg. 34,738 (June 10, 2013) (hereinafter referred to sometimes as "RH FIP Action").) The RH FIP focuses primarily on the "Best Available Retrofit Technology" ("BART") determinations for nitrogen oxides ("NO_X"). In addition to these written comments, PacifiCorp has submitted oral comments during public hearings held in Cheyenne, Wyoming on June 24 and July 17, 2013 and in Casper Wyoming on July 26, 2013.

PacifiCorp believes that the Wyoming RH SIP complies with all applicable requirements and should be approved in total by EPA . PacifiCorp also believes that EPA's proposed disapproval of the Wyoming RH SIP, and EPA's proposed adoption of its RH FIP, are flawed because of the following main reasons, as explained more fully below.

* **BART Bootstrap.** EPA claims that Wyoming failed to properly consider two BART factors (cost and modeled visibility improvement) in connection with Wyoming's BART NO_X determinations. As its chosen remedy for these alleged failures, EPA disapproved Wyoming's entire five-factor BART NO_X determinations for five PacifiCorp BART Units, performed its own BART analysis for each unit (leaving out some factors as explained below), and issued its own BART determinations. This is little more than a classic bootstrap maneuver by EPA in order to take over the regional haze program in Wyoming (and other states) that the Clean Air Act ("CAA") intended to be administered by the states. Even if EPA found that Wyoming committed errors with part of its BART determinations, it should have identified the errors, allowed Wyoming to correct them, and instructed Wyoming to reissue its BART determinations.

* **Remaining Useful Life.** PacifiCorp is submitting to EPA new information demonstrating a shorter useful life than EPA assumed in its BART analyses for Naughton Units 1 and 2, and Dave Johnston Unit 3. Accordingly, EPA must redo its BART analyses before taking final action on its proposed RH FIP. This new information, in turn, significantly changes the cost analyses for these units, and demonstrates that EPA's proposed BART controls are not cost-effective. This new information regarding useful lives is contained in Section 6.D of these comments.

* **Potential Unit Retirement.** PacifiCorp expects that EPA's proposed action requiring SCR on Naughton Unit 1, Naughton Unit 2, and Dave Johnston Unit 3 is not justifiable for its customers. As a result, if EPA makes the SCR requirements final, that action is expected to lead to the retirement or gas conversion of PacifiCorp units by the compliance date. Retirement and fuel switching are outside of the scope of the regional haze program and EPA lacks the authority to impose BART controls that results in such. Also, PacifiCorp identifies the significant energy and economic costs relating to retirements or fuel-switching that EPA must consider before finalizing the proposed RH FIP.

* **EPA's Cost and Visibility Analyses.** In the RH FIP Action, EPA indicated that it had received "new information" which resulted in it not taking action on its prior proposal and instead proposing a new action. This new action, the RH FIP Action, proposes to require additional SCR controls as BART at many additional electric generating units. In terms of dollars per ton of NO_X removed and the modeled change in visibility ("ΔdV") of visibility improvement, however, EPA's consideration of "new information" did not significantly change the results identified in Wyoming's BART analyses. The small differences between EPA's and Wyoming's analyses do not justify EPA rejecting Wyoming's carefully balanced BART determinations and imposing its own will. Nor do the minor differences in results justify the significant changes EPA has made in the controls that it now prescribes in its proposed FIP.

* **EPA's Review of Other BART factors**. EPA's re-proposal has only considered new information related to the costs of controls and the modeled visibility impacts, and did not consider the other BART factors. For this reason alone, EPA's RH FIP Action is unlawful.

* **Alternate Controls.** The Wyoming RH SIP is supported by relevant facts and law, and should be approved by EPA in total. However, since EPA requested consideration of alternate approaches to its BART proposals, PacifiCorp discusses possible alternate approaches in Section 11 (which incorporate the remaining useful life, cost updates and other relevant issues discussed in Section 6).

INTRODUCTION

PacifiCorp supplies electricity to more than 1.8 million residential and business customers in Wyoming and five other western states. Twenty-six of its generating resources are coal-fueled units. PacifiCorp operates 19 of these units in Wyoming and Utah. Among those, 14 are BART-eligible and ten of those are located in Wyoming ("BART Units"). PacifiCorp also has an ownership interest in four coal-fueled units located in Colorado, two units in Montana, and one unit in Arizona. Five of these seven units are BART-eligible units.

EPA proposes to disapprove portions of the Wyoming RH SIP, and implement a RH FIP, for BART NO_X at PacifiCorp's Dave Johnston Unit 3 ("DJ3"), Dave Johnston Unit 4

("DJ4"), Naughton Units 1 and 2 ("NTN 1 & 2"), and Wyodak Unit 1 ("Wyodak"). EPA's RH FIP Action also rejects the Wyoming RH SIP, and imposes a RH FIP, for the NO_X Reasonable Progress Goals at Dave Johnston Units 1 and 2 ("DJ 1 & 2"). EPA ultimately proposes to "approve" Wyoming's BART NO_X determinations for Jim Bridger Units 1, 2, 3, and 4, but requests comment on what EPA characterizes as a "second proposed approach" for Jim Bridger Units 1 and 2 that would require the installation of selective catalytic reduction ("SCR") as BART NO_X within five years of EPA's final action. EPA also proposes to approve Wyoming's BART NO_X determinations for Naughton Units 3, but requests comment on the possible conversion of Naughton Unit 3 to a natural gas fired unit.

Because the Wyoming RH SIP and EPA's RH FIP Action have a unique and significant impact on PacifiCorp and its customers, PacifiCorp offers these comments.

SUMMARY AND OUTLINE OF COMMENTS

PacifiCorp believes that the Wyoming RH SIP complies with all applicable requirements and should be approved in total by EPA. EPA's proposed partial disapproval of the Wyoming RH SIP, and EPA's associated RH FIP, are contrary to the CAA and the federal regional haze program, and also are arbitrary and capricious and outside the scope of EPA's authority.

PacifiCorp submits that:

(1) EPA fails to afford the required deference to Wyoming's significant discretion under the CAA and Regional Haze Program.

(2) EPA illegally bases its proposed partial disapproval of the Wyoming RH SIP on a fabricated "reasonableness" standard not found in the CAA.

(3) EPA exceeded its authority under Section 110 of the CAA.

(4) EPA improperly proposed a rulemaking (the RH FIP) without completing the required legal analyses.

(5) EPA improperly proposed to reject Wyoming's BART determinations for NO_X, which were based on Wyoming's own thorough and well-supported five-factor BART analyses.

(6) EPA improperly proposed a FIP based on an incomplete and flawed five-factor BART analysis.

(7) EPA improperly assumed that post-combustion controls for NO_X can be BART, contrary to Appendix Y and the regional haze requirements.

(8) EPA arbitrarily proposed to require "reasonable progress" controls at DJ 1 & 2 using a different standard than EPA used for other Wyoming sources, and elsewhere.

(9) EPA failed to take into account the collective impact to PacifiCorp of EPA's proposed RH FIP Action, together with EPA's proposed and final actions in the other states where PacifiCorp owns affected facilities.

(10) EPA acted in an untimely fashion in reviewing the Wyoming RH SIP, to the extreme detriment of PacifiCorp, which already has installed, or is in the process of installing, controls mandated by the Wyoming RH SIP.

(11) At EPA's request, PacifiCorp provides information regarding control technology options that could be finalized either instead of, or in conjunction with EPA's RH FIP.

HISTORY OF THE WYOMING RH SIP

PacifiCorp summarizes the history of the Wyoming RH SIP to provide important context for understanding how EPA's RH FIP Action is improper.

On July 1, 1999, EPA first published regulations to address regional haze visibility impairment. Importantly, the regulations required states (not EPA) to address BART requirements for regional haze visibility impairment. In addition, the regulations allowed nine western states, including Wyoming, to develop regional haze plans based on the Grand Canyon Visibility Transport Commission ("GCVTC") recommendations for stationary SO_2 sources in lieu of making BART determinations. (*See* Wyoming RH SIP, pg. 89.) In accordance with the law, Wyoming developed the required plans.

In 2000, the Western Regional Air Partnership ("WRAP") submitted an Annex to the GCVTC recommendations that provided more details regarding the regional SO_2 milestones and backstop trading program recommended in the GCVTC Report. The Annex also included a demonstration that the milestones program would achieve greater reasonable progress than would be achieved by the application of BART for SO_2 in the region. The Annex was approved by EPA in 2003, but this approval was later vacated by the D.C. Circuit Court of Appeals in 2005 due to problems with the methodology that was required in the regional haze rule for demonstrating greater reasonable progress than BART. (*See id.*)

On December 29, 2003, the State of Wyoming submitted a regional haze SIP to meet the requirements of 40 C.F.R. § 51.309. The 309 SIP, and subsequent revisions addressed the first phase of regional haze requirements, with an emphasis on stationary source SO_2 emission reductions and a focus on improving visibility on the Colorado Plateau. In the 309 SIP submittal, Wyoming committed to addressing additional visibility improvements in Wyoming's seven Class I areas by means of a future additional SIP meeting the requirements of 309(g). (*See* WYOMING RH SIP at pg. 1.)

After Wyoming submitted the 309 SIP to EPA in 2003, EPA revised both 40 C.F.R. §§ 51.308 and 309 in response to numerous judicial challenges. Following a lengthy public review period, EPA published new versions of 40 CFR Part 51 and Appendix Y in the Federal Register in 2005 (collectively the "Regional Haze Rules"). As a result, Wyoming submitted revisions to the 309 SIP on November 21, 2008. (*See id.*)

A few years earlier on October 10, 2006, Wyoming's Environmental Quality Council ("EQC") approved a State-only BART regulation (Chapter 6, Permitting Requirements, Section 9, Best Available Retrofit Technology) that became effective in December 2006. This regulation required BART-subject sources to submit an application for a BART determination and a BART permit, according to a schedule determined by Wyoming. (*See* Wyoming RH SIP at pg. 90.)

PacifiCorp submitted individual BART permit applications for its Wyoming BART Units in 2006 and early 2007. PacifiCorp also submitted subsequent information and amendments to Wyoming in support of the BART permit applications. Wyoming published its BART application analyses for PacifiCorp's Wyoming BART Units in May of 2009, and solicited public comment. Public hearings were held for each affected facility during August of 2009. After reviewing and responding to public comments, Wyoming issued BART permits for PacifiCorp's Wyoming BART Units in December 2009.

On February 26, 2010, PacifiCorp appealed the BART permits for Naughton Unit 3 and the four Jim Bridger units to the Wyoming Environmental Quality Council. In particular, PacifiCorp appealed Wyoming's determination that SCR must be installed as BART for Naughton Unit 3 and as part of regional haze long term strategy ("LTS") requirements for Jim Bridger Units 1-4. After appealing the case to the EQC, the parties entered into a settlement agreement in November of 2010. EPA chose not to participate in, challenge or influence Wyoming's decision to issue the BART permits, PacifiCorp's appeal or the subsequent resolution by settlement.

On December 8, 2010, Wyoming held a public hearing in Cheyenne, Wyoming to receive comments on the 309(g) portion of the Wyoming RH SIP. In addition, Wyoming collected public comment on the 309 SIP revisions. After carefully considering all comments, and based upon the settlement agreement, Wyoming Air Quality Division ("WAQD") determined that SCR was not BART for the Jim Bridger Units. Instead, WAQD determined that SCR should be installed over time as part of Wyoming's LTS. On January 7, 2011, Wyoming submitted its 309 SIP (concerning SO_2) and the Wyoming RH SIP (which includes the BART and Reasonable Progress NO_X controls and limits addressed in these comments).[1]

[1] For a reason that is not clear from the record, EPA claims Wyoming's 309(g) SIP, which is also referred to herein as Wyoming's "RH SIP," was submitted on January 12, 2011. 77 Fed. Reg. at 33,022. However, the RH SIP is dated "January 7, 2011" on its title page. *Found at* http://deq.state.wy.us/aqd/308%20SIP/309(g)%20SIP%201-7-11%20Clean%20Final.pdf.

EPA approved the 309 SIP on December 12, 2012. 73 Fed. Reg. 73,926. PacifiCorp's comments herein focus only on the Wyoming RH SIP , primarily as it relates to BART NO_X determinations.

As required by Wyoming's state-only BART regulations, the BART permits and the Wyoming RH SIP and 309 SIP, PacifiCorp installed controls at many of its Wyoming facilities at the cost of hundreds of millions of dollars. The equipment already installed is listed in the following table. Capital costs shown are total project costs and are not limited to PacifiCorp's share of costs for jointly owned facilities.

Table 1

Unit	Wyoming SIP NO_X Technology	Wyoming SIP SO_2 Technology	Wyoming SIP PM Technology	Total Capital Cost*
Naughton 1	LNB/OFA Spring 2012	New Scrubber Spring 2012	ESP upgrade August 2010	$130 million
Naughton 2	LNB/OFA Fall 2011	New Scrubber Fall 2011	ESP upgrade August 2010	$151 million
Jim Bridger 1	LNB/OFA Spring 2010	Scrubber Upgrade Spring 2010	ESP upgrade 2007	$31 million
Jim Bridger 2	LNB/OFA Spring 2005	Scrubber Upgrade Spring 2009	ESP upgrade 2007	$28 million
Jim Bridger 3	LNB/OFA Spring 2007	Scrubber Upgrade Spring 2011	ESP upgrade 2007	$33 million
Jim Bridger 4	LNB/OFA Spring 2008	Scrubber Upgrade Spring 2008	ESP upgrade 2007	$14 million
Dave Johnston 3	LNB/OFA Spring 2010	New Scrubber Spring 2010	New Baghouse Spring 2010	$324 million
Dave Johnston 4	LNB/OFA Spring 2012	New Scrubber Spring 2012	New Baghouse Spring 2012	$115 million
Wyodak	LNB/OFA Spring 2011	Scrubber Upgrade Spring 2011	New Baghouse Spring 2011	$141 million
Total Capital				$967 million

* Total capital costs shown include allowance for funds used during construction.

In addition to these controls that are already in service, engineering is currently underway to convert Naughton Unit 3 to be fueled with natural gas. PacifiCorp is pursuing this course in lieu of installing the BART requirements (i.e. upgrading the scrubber and installing a baghouse and SCR) because BART controls are not economical for PacifiCorp customers compared to the natural gas alternative. This conversion will reduce the hourly and annual NO_X emissions from Naughton Unit 3 to amounts even lower than the required BART controls would have achieved. Naughton Unit 3 is an example of how stringent BART requirements can result in retirement and/or the refueling of a coal-fueled unit.

In addition, consistent with the Wyoming RH SIP and related requirements, engineering and permitting is underway for the installation of SCR on Jim Bridger Unit 3 in 2015 and Jim Bridger Unit 4 in 2016.

Controls installed to date in compliance with the Wyoming RH SIP and BART permits have reduced annual SO_2 emissions by 56% (72,400 tons per year to 31,500 tons per year) and NO_X emissions by 48% (70,900 tons per year to 36,800 tons per year), with the resulting visibility improvements. When all of the controls required under the Wyoming RH SIP are installed, annual SO_2 emissions will have been reduced to 27,600 tons per year (a 62% reduction) and annual NO_X emissions will have been reduced to 19,200 tons per year (a 73% reduction).

DETAILED COMMENTS

(1) EPA Fails to Afford the Required Deference to Wyoming's Significant Discretion Under Clean Air Act and the Regional Haze Program.

EPA's RH FIP Action failed to afford the required deference to the technical, policy and other discretion granted to Wyoming under the CAA and regional haze program.

Congress added § 169A to the CAA in order to address the "impairment of visibility" in Class I areas that "results from man-made air pollution." This provision of the CAA, in turn, describes separate roles for EPA, the states, and major sources such as PacifiCorp's BART Units.

EPA -- EPA's roles are to create a report, *see* CAA § 169A(a)(2)-(3), create regional haze regulations, *see* CAA § 169A(a)(4), provide guidelines for the states, *see* CAA § 169A(b)(1), and determine whether RH SIPs submitted by the states follow the regulations and guidelines, and contain the required elements. CAA § 110.

States -- The States' roles, which are central to the regional haze program, are intended to be accomplished using substantial discretion which, in turn, requires significant deference from EPA.[2] States are required to submit a RH SIP that contains "emission limits, schedules of compliance and other measures as may be necessary to make reasonable progress toward meeting the national goal." CAA § 169A(b)(2). States also must "determine[]" BART for "each major stationary source." CAA 169A(b)(2)(A). [3]

[2] Where, as here, the CAA gives decision-making authority to the states, EPA must defer to Wyoming's judgments unless EPA meets it burden of showing that Wyoming acted unreasonably by failing to follow the applicable statutes, regulations and guidelines, or by failing to support with evidence its decision making. See Alaska Dept. of Envtl. Conservation v. EPA, 540 U.S. 461,494 (2004). EPA has made no such showing herein the RH FIP Action. Therefore, Wyoming's BART determinations as contained in the Wyoming RH SIP should stand and EPA should not make final the RH FIP final.

[3] A recent decision by the 10th Circuit Court of Appeals affirmed that "it is undoubtedly true that the statute gives states discretion in balancing the five BART factors…." See

BART Sources -- Finally, BART sources, such as PacifiCorp's BART Units, are required to "procure, install, and operate (BART) as expeditiously as practicable." CAA § 169A(b)(2)(A).

Thus, the CAA mandates that states have the primary role in developing RH SIPs to protect visibility in Class I areas. Likewise, the Regional Haze Rules make clear that states have the responsibility to create and implement RH SIPs. In contrast, EPA's role is to develop "guidelines" for the states to use in implementing RH SIPs and to determine whether states followed those guidelines. CAA § 169A(b)(1). In short, the CAA anticipates that states, using their discretion, develop RH SIPs using EPA guidelines. This is exactly what Wyoming did in issuing BART permits and developing the Wyoming RH SIP.

In issuing regional haze guidelines, EPA recognized the broad discretion granted to the states by the CAA. Specifically, EPA adopted guidance to address BART determinations for certain large electrical generating facilities, referred to as "Appendix Y."[4] EPA created further guidance in the Federal Register responding to comments concerning the then-proposed Appendix Y, referred to as the "Preamble." EPA recognized in the Preamble that "how <u>states</u> make BART determinations or how they determine which sources are subject to BART" are among the issues "where the Act and legislative history indicate that <u>Congress evinced a special concern with insuring that states would be the decision makers.</u>" 70 Fed. Reg. 39,104, 39,137 (July 6, 2005) (emphasis added). Likewise, in analyzing the applicability of certain executive orders, EPA stated that "<u>ultimately states will determine the sources subject to BART and the appropriate level of control for such sources</u>" and that "<u>states will accordingly exercise substantial intervening discretion in implementing the final rule.</u>" *Id.* at 39,155 (emphasis added).[5]

Okla. V. EPA, No. 12-9526, 2013 U.S. App. LEXIS 14634, (10th Cir. July 19, 2013). Although the court ultimately found in a divided panel that EPA was within its authority to reject the Oklahoma RH SIP and impose a RH FIP because the state of Oklahoma had not properly followed some of EPA's guidelines in making BART determinations, such is not the case here. In this case and as more fully explained herein, the state of Wyoming followed EPA's guidelines in making BART determinations in support of the Wyoming RH SIP. Having done so, EPA must give deference to the discretion the state of Wyoming used in making technical and policy regional haze decisions, including BART determinations. In that case, EPA further must approve the RH SIP and not make final the RH FIP.

[4] "Guidelines for BART Determinations under the Regional Haze Rule," 40 C.F.R. Part 51, Appendix Y.

[5] EPA also has explained that "(i]n some cases, the <u>State</u> may determine that a <u>source has already installed sufficiently stringent emission controls</u> for compliance with other programs . . . such that <u>no additional controls would be needed</u> for compliance with the BART requirement." 64 Fed. Reg. 35714, 35740 (July 1, 1999) (emphasis added). EPA further acknowledges that, in making BART determinations, "<u>[s]tates</u> are <u>free</u> to

The U.S. Court of Appeals for the D.C. Circuit has affirmed that EPA's role regarding regional haze programs is limited and that a state's role is paramount. Indeed, the Court found that the CAA "calls for states to play the lead role in designing and implementing regional haze programs." *American Corn Growers Ass'n v. E.P.A.,* 291 F.3d 1, 2 (D.C. Cir. 2002). The court also reversed a portion of EPA's original Regional Haze Rule because it found that EPA's method of analyzing visibility improvements distorted the statutory BART factors and was "inconsistent with the Act's provisions giving the states broad authority over BART determinations." *Id.* at 8; (*see also Utility Air Regulatory Group v. EPA* , 471 F.3d 1333, 1336 (D.C. Cir. 2006) (The second step in a BART determination "requires states to determine the particular technology that an individual source 'subject to BART' must install.")). The court in *American Corn Growers* emphasized that Congress specifically entrusted states with making BART five-factor analysis decisions: "To treat one of the five statutory factors in such a dramatically different fashion distorts the judgment Congress directed the states to make for each BART-eligible source." *American Corn Growers*, 291 F.3d at 6.

The court in *American Corn Growers* also outlined the relevant legislative history that recounts a specific agreement reached in Congress which granted this authority to the states: "The 'agreement' to which the Conference Report refers was an agreement to reject the House bill's provisions giving EPA the power to determine whether a source contributes to visibility impairment and, if so, what BART controls should be applied to that source. Pursuant to the agreement, language was inserted to make it clear that the states—not EPA —would make these BART determinations. <u>The Conference Report thus confirms that Congress intended the states to decide which sources impair visibility and what BART controls should apply to those sources. The Haze Rule attempts to deprive the states of some of this statutory authority, in contravention of the Act.</u>" *Id.* at 8 (citations omitted) (emphasis added). EPA's RH FIP Action makes the same mistake and, if finalized, will be similarly reversible.

In sum, based on the language in the CAA, the Regional Haze Rules, EPA's own guidelines, and case law, the states have significant discretion when creating RH SIPs. EPA failed to properly account for that discretion in analyzing the Wyoming RH SIP. EPA should have acknowledged that the Wyoming RH SIP followed the law and was supported by the facts. Examples of EPA ignoring Wyoming's discretion include:

- visibility improvement;
- cost effectiveness analysis;
- modeling;
- application of the five BART factors; and
- reasonable progress analyses.

<u>determine the weight and significance</u> to be assigned to each factor." 76 Fed. Reg. 64,186, 64,192 (emphasis added).

EPA's failure to recognize Wyoming's discretion in these areas is arbitrary and capricious.

(2) EPA Illegally Bases its Disapproval on an Unsupported "Reasonableness" Standard not Found in the CAA.

A. EPA's "Reasonableness" Standard is Overly Subjective and Arbitrary.

EPA cannot sidestep the CAA's mandate for state discretion by developing and applying a new "reasonableness" standard for evaluating and rejecting that discretion. EPA's RH FIP Action, however, does just that. For example, EPA incorrectly declared "the state's BART analysis and determination must be reasonable in light of the overarching purpose of the regional haze program." (*See* 78 Fed. Reg. at 34,743, emphasis added.) This overly broad and illegal "reasonableness" standard allows EPA to reject any BART determination that EPA dislikes by merely arguing that a state's BART determination is "unreasonable" and without comparing the state's determination to any firm or fixed standards. EPA's "reasonableness" standard requires statutory and regulatory limitations on EPA's authority to disapprove a reasoned RH SIP. The fallacy of EPA's improper reasonableness standard is made even more apparent in its application by EPA, which simply rejects as "unreasonable" many of Wyoming's BART-related decisions without offering sufficient justification of why that is the case.

B. EPA Uses the "Reasonableness" Standard to Substitute its Judgment for Wyoming's.

In creating and employing its reasonableness standard, EPA goes to an even greater extreme by defining "reasonable" in the most self-serving manner imaginable. In short, EPA defines "reasonable" to mean that EPA agrees with the state's exercise of discretion, and it defines "unreasonable" to mean EPA does not agree with the state. (*See e.g., 78* Fed. Reg. at 34,767, where EPA substitutes its consideration of costs and visibility improvement for Wyoming's). In this way, EPA attempts to bootstraps itself into the role of the sole decision-maker of what is BART and what is not. The CAA does not countenance such overreaching by EPA.

The egregiousness of EPA's actions becomes even more apparent when comparing EPA's conclusions regarding cost and visibility impacts for certain of PacifiCorp's BART Units against the cost and visibility impact conclusions reached by Wyoming for the same units. Table 2 below provides a comparison between Wyoming's modeled ΔdV improvements and EPA's ΔdV improvements based on the "new information" EPA claims it has developed. Recognizing EPA's conclusion that one deciview is barely perceptible to the human eye and considering the inaccuracies and limitations of the model inputs and versions of the visibility models being used, there is no significant difference between Wyoming's results and EPA's results. Additionally, without any "bright line" test regarding the amount of visibility improvement that justifies a given control device, EPA cannot show that these insignificant differences would have any impact on the BART determinations for PacifiCorp's BART Units.

Table 2

COMPARISON OF WYOMING'S AND EPA'S FIVE-FACTOR ANALYSIS RESULTS - VISIBILITY				
Visibility Analysis Comparison - Modeled ΔdV Improvement				
Unit	Technology	State Analysis	EPA Re-Proposal	Difference
Naughton Unit 1	LNB/OFA	0.79	0.84	0.05
	SCR	1.07	1.23	0.16
Naughton Unit 2	LNB/OFA	0.70	0.97	0.27
	SCR	1.10	1.42	0.32
Dave Johnston Unit 3	LNB/OFA	0.77	0.64	(0.13)
	SCR	1.16	1.00	(0.16)
Dave Johnston Unit 4	LNB/OFA	0.71	0.84	0.13
	SNCR	0.80	0.95	0.15
Wyodak	LNB/OFA	0.25	0.24	(0.01)
	SNCR	0.40	0.38	(0.02)

Table 3 below provides a comparison between Wyoming's cost estimates (dollars per ton of NO_X removed) and EPA's cost estimates developed based on "new information". Recognizing that EPA has stated that differences of up to $700 per ton[6] are insignificant, there is no significant difference between Wyoming's results and EPA's results.

Table 3

COMPARISON OF WYOMING'S AND EPA'S FIVE-FACTOR ANALYSIS RESULTS - $ PER TON REMOVED				
Cost Analysis Comparison - Dollar Per Ton NO_X Removed				
Unit	Technology	State Analysis	EPA Re-Proposal	Difference
Naughton Unit 1	LNB/OFA	$426	$444	$18
	SCR	$2,750	$2,318	-$432
Naughton Unit 2	LNB/OFA	$357	$342	-$15
	SCR	$2,848	$2,255	-$593
Dave Johnston Unit 3	LNB/OFA	$648	$599	-$49
	SCR	$3,243	$2,540	-$703
Dave Johnston Unit 4	LNB/OFA	$137	$246	$109
	SNCR	$323	$740	$417
Wyodak	LNB/OFA	$881	$1,027	$146
	SNCR	$958	$1,979	$1,021

For all of the criticism that EPA makes concerning the state's analyses, the reality is that the results of the analyses of both agencies are very similar. In some cases, EPA's

[6] 76 Fed. Reg. 38,997, 39,000

numbers (such as the cost of SNCR at Wyodak) provide less of a justification for EPA's chosen BART controls than Wyoming's numbers did in its analyses. However, EPA has used its broad and unjustified criticisms of the state's work to discredit the state's studies and usurp the discretion the state has applied to its BART determinations.

C. EPA's Subjective "Reasonableness" Standard Leads to Arbitrary and Inconsistent Results.

As shown in Table 3 above, EPA attempted to use post-hoc, immaterial changes that it calculated in costs and visibility improvements to justify usurping Wyoming's BART decision-making authority. EPA attempted this even though its actions run counter to the vast discretion it has given to other states' RH SIPs.

Oregon -- For example, despite EPA and Oregon differing in how each calculated BART costs that resulted in cost variance of over $700 per ton, EPA stated that such difference "between the two estimates would not materially affect ODEQ's evaluation." 76 Fed. Reg. 38,997, 39,000. EPA further explained that in "EPA's view, ODEQ's final selection of BART would not have changed even if the cost effectiveness had been adjusted to reflect the EPA Cost Manual."[7] *Id.* As explained above, the difference between the cost analyses under EPA's RH FIP Action and the Wyoming RH SIP similarly is immaterial. In Oregon, EPA approved the Oregon RH SIP in spite of those differences. In Wyoming, however, EPA used those differences to justify rejection of Wyoming's cost analyses.

Colorado -- In Colorado, the State's plan included a cost analysis that, according to EPA, "was not conducted … in accordance with EPA's Control Cost Manual." 77 Fed. Reg. 76,871, 76,875. In addition, EPA explained that Colorado "should have more thoroughly considered the visibility impacts of controlling emissions from Craig [Unit 1] on the various impacted Class I areas and not just have focused on the most impacted Class I area." *Id*. Nevertheless, after noting "there is room for disagreement about the State's analyses and appropriate limits" and admitting that EPA "may have reached different conclusions," EPA approved the State's RH SIP, explaining that "Colorado's plan achieves a reasonable result overall." *Id.* Again, in Colorado EPA met the requirement that it afford deference to states in the RH SIP process even when EPA may not agree with the methods used by the state to conduct a BART analysis. EPA should afford Wyoming the same degree of deference it afforded Colorado and Oregon, and failure to do so violates the CAA and regional haze program. As demonstrated by the impacts of the Wyoming RH SIP, it "achieves a reasonable result overall."

Wyoming -- EPA's inconsistency is not just limited to its disparate actions between states. In Wyoming , EPA acted inconsistently in its BART determinations between sources

[7] Remarkably, EPA rejected Wyoming's NO_x BART analyses for Naughton Units 1 and 2, even though the cost per ton between EPA's and Wyoming's numbers are less than $700 per ton. 78 Fed. Reg. 34,781,-82. While EPA respected Oregon's discretion to weigh the costs of BART controls despite not following the Control Cost Manual, here EPA ignored the State's discretion on the pretext it hadn't followed the Control Cost Manual.

within the state. For example, EPA accepted Wyoming's cost and visibility BART analyses for FMC Westvaco and General Chemical, along with the PM BART analyses for PacifiCorp's and Basin Electric's BART Units. At the same time, EPA rejected the NO_x BART cost and visibility analyses for PacifiCorp's and Basin Electric's BART Units. Wyoming, however, used the same BART analysis methodology for those BART Units at which EPA accepted the Wyoming BART analysis as it did at those BART Units for which EPA did not. The BART analysis employed by Wyoming was the same for all BART Units. By rejecting some cost and visibility analyses on the basis that they were improperly performed, while accepting others that were performed in the same manner, EPA acted arbitrarily and capriciously.

D. EPA Erred by not Analyzing Whether the BART Controls Required by its RH FIP are Necessary to Make Reasonable Progress

EPA should have judged Wyoming's BART determinations on the basis of whether or not the Wyoming BART determinations are "necessary" to make "reasonable progress."

EPA's Regional Haze Rules provide two regulatory paths to address regional haze. (*See* 77 Fed. Reg. 30,953, 30,957 (May 24, 2012).) "One is 40 CFR 51.308, requiring states to perform individual point source BART determinations and evaluate the need for other control strategies." *Id*. "The other method for addressing regional haze is through 40 CFR 51.309, and is an option for nine states termed the 'Transport Region States' which include: . . . Wyoming, . . . By meeting the requirements under 40 CFR 51.309, states are making reasonable progress toward the national goal of achieving natural visibility conditions for the 16 Class I areas on the Colorado Plateau." *Id.* Wyoming submitted the Wyoming RH SIPs under Section 309. Therefore, the requirements of Section 308 only apply to the extent required by Section 309.[8]

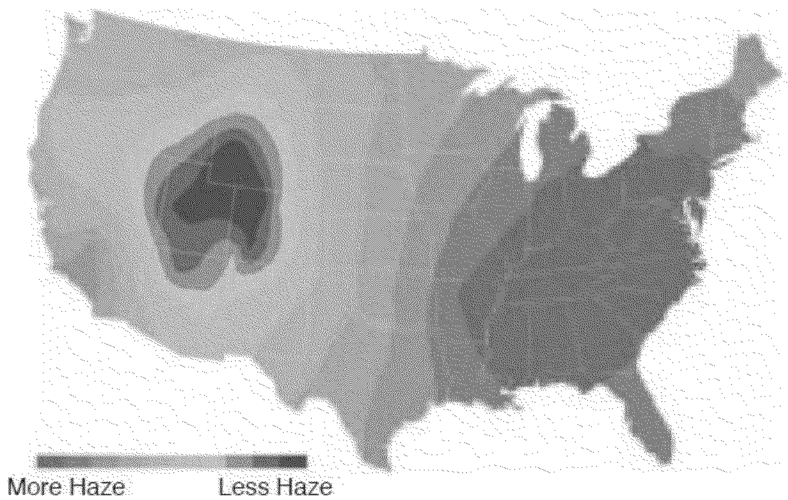
Importantly, NO_X emissions and controls under Section 309 are treated differently than NO_X emissions and controls under Section 308. This is because Congress and EPA purposefully focused Section 309 on addressing the issue of SO_2 emissions, the predominant cause of regional haze on the Colorado Plateau in the western US. By contrast, Section 309 recognizes that NO_X emissions have a significantly smaller impact on visibility on the Colorado Plateau. In fact, the WRAP estimated that "stationary source NO_X emissions result in nitrates that probably cause about 2 to 5 percent of the impairment on the Colorado Plateau." [9] Several illustrations in the WRAP NO_X report

[8] Section 51.309 "requires participating states to adopt regional haze strategies that are based on recommendations from the Grand Canyon Visibility Transport Commission (GCVTC)" which was established in 1991 to protect the 16 Class I areas on the Colorado Plateau. 77 Fed. Reg. at 30,957. These strategies included "Strategies for addressing smoke emissions from wildland fires and agricultural burning; provisions to prevent pollution by encouraging renewable energy development; and provisions to manage clean air corridors (CACs), mobile sources, and wind-blown dust, among other things." *Id.*

[9] "Stationary Source NO_X and PM Emissions in the WRAP Region: An Initial Assessment of Emissions, Controls, and Air Quality Impacts," October 1, 2003, at I-3, *found at* http://www.wrapair.org/forums/mtf/nox_-pm.html. The state of Wyoming relied upon this

show that nitrate emissions have very little impact on Class I areas in or near Utah and Wyoming. (*See id. at* III-3 to III-6.) The WRAP report also explains that "NO_X controls will have a relatively small impact on PM and visibility in the West." (*Id.* at IV-20 and IV-21.)

The Wyoming RH SIP, including BART determinations for NO_X, is consistent with the WRAP's NO_X information, and also properly acknowledges the relatively small impact nitrates from stationary sources like PacifiCorp's BART Units have on visibility impairment in Wyoming. Wyoming's RH SIP, page 62, states that "the majority of nitrate stems from mobile sources." The RH SIP also explains that in all but one Class I area "contributions from other states and Canada are much larger than contributions from inside Wyoming." *Id.* Wyoming correctly determined, consistent with the WRAP reports and other data, that controlling NO_X emissions from stationary sources like PacifiCorp's BART Units would yield very little visibility improvement in Wyoming. EPA's own regional haze visibility map shows that visibility in Wyoming is among the best in the country. (*See below and* Attachment 1, EPA Regional Haze Map.)



Haze conditions vary across the country. Eastern U.S. areas have more haze due to higher pollutant and humidity levels.

In light of the above information, it is understandable that Section 309 focuses on addressing SO_2 emissions. Indeed, GCVTC and WRAP focused their efforts primarily on SO_2 emissions because the research indicated this pollutant had the greatest impact on visibility. "Recommendations for Improving Western Vistas," authored by GCVTC, (June 10, 1996) at page 32 (identifying sulfates as "the most significant contributor to visibility impairment" from stationary sources).[10] In a separate action, EPA

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information in formulating its NO_X and PM BART control strategy. January 7, 2011 309(g) RH SIP, pages 61-66 and 188-196. Additionally, to the extent NO_X controls would be required, WRAP stated that "substantial reduction may be feasible with commercially-available technologies for about \$300 to \$1,200 per ton." *Id.* at I-4.

[10] *Found at* http://www.wrapair.org/WRAP/reports/GCVTCFinal.PDF .

acknowledged that Wyoming has complied with the Section 309's SO_2 requirements and made great progress[11] towards improving and protecting visibility as a result.

For all of these reasons, Section 309 takes a different approach to NO_X emissions than does Section 308, placing much less emphasis on the need for significant reductions in NO_X emissions and instead focusing almost all attention and resources in the western U.S. on reducing SO_2 emissions. EPA's RH FIP Action, with its incredibly expensive and unneeded NO_X control equipment, ignored the focus and intent of Section 309 and refused to acknowledge the discretion available to Wyoming to balance this information in making its BART determinations.

Additionally, as a result of the lesser emphasis in Section 309 on NO_X emissions, Section 51.309(d)(4)(vii) requires a RH SIP to "contain any necessary long term strategies and BART requirements for stationary source . . . NO_X emissions." Section 308, by contrast, does not include a similar "necessary to achieve reasonable progress" threshold for BART. The difference between the two requirements is both intentional and meaningful. If a state like Wyoming finds that a particular BART requirement is not "necessary" to make "reasonable progress," then that BART requirement should not be required as part of the RH SIP. This interpretation is supported by EPA's own position in *Central Arizona Water Conservancy District v. United States*, 990 F.2d 1531 (9th Cir. 1993). There, "EPA chose not to adopt the emission control limits indicated by the BART analysis, but instead to adopt an emissions limitations standard that would produce greater visibility improvement at a lower cost." *Id.* at 1543 (emphasis added). The court agreed with EPA, stating that "Congress's use of the term 'including' in § 7491(b)(2) prior to its listing BART as a method of attaining 'reasonable progress' supports EPA's position that it has the discretion to adopt implementation plan provisions other than those provided by BART analyses in situations where the agency reasonably concludes that more 'reasonable progress' will thereby be attained." *Id.* (emphasis added). This same rationale applies to the term "necessary" in Section 309. Therefore, in rejecting Wyoming's RH SIP and adopting a RH FIP, EPA is required to show that the Wyoming RH SIP will not achieve "necessary reasonable progress" towards the visibility goal, EPA's RH FIP will. EPA has failed to provide any support for such a position.

As previously noted, with the exception of the controls required on Naughton Unit 3, PacifiCorp has installed all of the BART controls required by the Wyoming RH SIP and BART Permits. These controls were installed from 2005 through 2012. The charts[12] included as Attachment 2 identify the visibility improvement that has been made through 2009 at the Mount Zirkel Wilderness Area (used in the Jim Bridger BART evaluations) and Wind Cave National Park (used in the Wyodak and Dave Johnston BART evaluations). The charts in the attachment, which are based on actual monitored visibility impairment, demonstrate that the Wyoming RH SIP already has made significant progress in reducing nitrate concentrations and further demonstrate that Wyoming's

[11] PacifiCorp's timely installation of required SO_2 controls at its Wyoming BART Units has been a large part of this success.

[12] http://vista.cira.colostate.edu/TSS/Results/HazePlanning.aspx

reasonable progress goal is on track through the 2008 - 2017 planning period. These charts provide graphic evidence that EPA's RH FIP Action is not "necessary" to meet reasonable progress goals for nitrates in these Class I areas. As a result, EPA should withdraw its RH FIP.

(3) <u>EPA Exceeded its Authority Under Section 110 of the CAA.</u>

EPA does not have the authority under the CAA to issue a RH FIP in this instance. EPA contends its review of the Wyoming RH SIP is "pursuant to section 110 of the CAA." 7 Fed. Reg. 34,738. Section 110(a)(2) provides the general requirements that a SIP must contain. Importantly, EPA's role under Section 110 in reviewing states' RH SIPs is narrow: "With regard to implementation, the (CAA) confines the EPA to the ministerial function of reviewing SIPs for consistency with the (CAA)'s requirements." *Luminant Generation Co., LLC v. EPA,* 675 F.3d 917, 921 (5th Cir. 2012) (citing § 110(k)(3)).

As the court in *Luminant* explained, if the State's submissions "satisfy those basic requirements (found in § 110), the EPA must approve them," and "(t)hat is the full extent of the EPA's authority in the SIP-approval process because that is all the authority that the CAA confers." *Id.* at 932. Here, Wyoming submitted a RH SIP that met the requirements of Section 309 and included all the required elements. The Wyoming RH SIP submittals are well developed and comprehensive. EPA admits that Wyoming considered all five BART factors. 78 Fed. Reg. at 34,748. Therefore, EPA's role was to review whether Wyoming followed the regional haze requirements, including Appendix Y, and provided factual support for the Wyoming RH SIP. Congress did not authorize EPA to "second guess" Wyoming's BART decision making, or to substitute its own judgment, simply because EPA would prefer different BART and Reasonable Progress NO_X controls.

EPA should not impose a RH FIP until it has issued a final rule disapproving the Wyoming RH SIP. 42 U.S.C. § 7410(c)(1)(B). EPA should first conduct a rulemaking and take public comment on the Wyoming RH SIP submission, issue its determination on the RH SIP, and then seek input from the State. (*See* 42 U.S.C. § 7410(c)(1)(B); *see also* 42 U.S.C. § 7607(d)(B) (rulemaking provisions apply to "the promulgation or revision of an implementation plan by the Administrator under section 7410(c)") Otherwise, EPA removes the State from its assigned role as the one determining BART.

The facts here illustrate this problem. EPA initially agreed with Wyoming's BART determinations for Naughton Units 1 and 2, and Dave Johnston Unit 3. EPA then reversed itself, supposedly on the basis of new cost and visibility information. Without offering Wyoming any chance to review the new information and issue a new BART determination, EPA disapproved Wyoming's BART determination for these units, and instituted new BART determinations for these units through a RH FIP. EPA's failure to provide Wyoming an opportunity to review this new information, and address it through a revised BART determination, violates the applicable Clean Air Act statutes.

The CAA defines a "Federal Implementation Plan" or FIP as "a plan (or portion thereof) promulgated by the (EPA) Administrator to fill all or a portion of a gap or otherwise correct all or a portion of an inadequacy in a State implementation plan (or SIP)." 42 U.S.C. § 7602(y) (emphasis added). Until EPA first assesses the Wyoming RH SIP, develops a proposed rule to approve or disapprove the Wyoming RH SIP, solicits and receives public comment on that proposed rule, considers the comments and information, and takes final action on whether (and to what extent) to approve the Wyoming RH SIP, EPA cannot know whether there is a "gap" in the Wyoming RH SIP that needs to be filled or whether (and to what extent) there is an "inadequacy" in the Wyoming RH SIP that needs to be corrected. *Id.* Moreover, EPA's failure to obtain public comments prior to proposing a RH FIP deprives Wyoming of an opportunity to correct any "deficiencies" identified by EPA. Here, where EPA claims to have obtained new cost and visibility information but did not allow Wyoming an opportunity to review and act on the new information, EPA's final determination regarding the Wyoming RH SIP ignores the State's authority under the CAA (including the regulatory programs implicated by CAA § 169A) to design and implement plans to control air pollution control within its borders. (*See* 42 U.S.C. § 7401(a)(3).) Therefore, EPA illegally seeks to impose its RH FIP and should withdraw the same.

(4) EPA Proposed a Rulemaking (the RH FIP) Without Completing the Required Legal Analysis.

A. EPA Failed to Follow the Requirements of Executive Orders 13211 and 12866.

EPA's RH FIP Action states that EPA's proposed action is not subject to Executive Order 13211, "Actions Concerning Regulations that Significantly Affect Energy Supply, Distribution, or Use" (66 Fed. Reg. 28,355 (May 22, 2001)), because the proposed action "is not a significant regulatory action under Executive Order 12866." 78 Fed. Reg. at 34,790. EPA further claims the proposed RH FIP is not a "significant regulatory action" under Executive Order 12866 because the "proposed FIP applies to only five facilities" and is "therefore not a rule of general applicability." EPA is incorrect, and should withdraw its RH FIP on these grounds.

Executive Order 13211 provides that agencies shall submit a statement of energy effects for matters "identified as significant energy actions." A "significant energy action" is defined as "any action by an agency … that promulgates or is expected to lead to the promulgation of a final rule or regulation … that is a significant regulatory action under Executive Order 12866 or any successor order" and "likely to have a significant adverse effect on the supply, distribution, or use of energy"; or is "designated by the Administrator of the Office of Information and Regulatory Affairs as a significant energy action." *Id.* § 4(b) (emphasis added).

Executive Order 12866, in turn, which concerns Regulatory Planning and Review, defines a "significant regulatory action" as any regulatory action that is likely to result in a rule that may:

> (1) Have an <u>annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs</u>, the environment, public health or safety, or State, local, or tribal governments or communities; . . .

58 Fed. Reg. 51,735, 51,738 (Oct. 4, 1993) (emphasis added).

According to PacifiCorp's current estimates (excluding allowance for funds used during construction "AFUDC"), it will spend more than $100 million dollars in capital costs alone in 2014 ($225 million), 2015 ($139 million), 2017 ($146 million) and 2018 ($118 million) to comply with EPA's RH FIP for Wyoming (based on alternative "one" for the Jim Bridger plant). If regional haze compliance costs currently imposed or approved by EPA on PacifiCorp's BART Units in Arizona and Colorado are factored in, the total capital cost impacts to PacifiCorp in any given year would be significantly higher; increasing to approximately $246 million in 2014, $190 million in 2015, $168 million in 2016, $181 million in 2017, and $118 million in 2018. Also, because the BART NO_X and PM determinations have not yet been approved by EPA for PacifiCorp's BART Units in Utah, EPA's ultimate BART requirements in Utah likely will add even more costs in overlapping installation and compliance years, with total project costs for SCR installations on PacifiCorp's Utah units currently estimated to cost in excess of $150 million per unit to install (again, excluding AFUDC). Based upon these basic costs alone, there is no doubt that EPA's RH FIP Action meets the definition of a "significant regulatory action." Other large costs, including those related to EPA's BART determinations for Basin Electric, also should be factored into this analysis together with PacifiCorp's costs because they are part of the same "sector of the economy." Also, as demonstrated by PacifiCorp's July 12, 2012, submittal in this docket, EPA's RH FIP Action will have an adverse effect on the supply and distribution of electricity within PacifiCorp's system. Therefore, EPA's determination that Executive Order 13211 did not apply is incorrect, and arbitrary and capricious.

Moreover, EPA has admitted in the proposed rule that system-wide "affordability" costs should be part of the BART analysis. 78 Fed. Reg. at 34,756. Because EPA's RH FIP Action is a "significant regulatory action," EPA must prepare a "Statement of Energy Effects" for the Administrator of the Office of Information and Regulatory Affairs, Office of Management and Budget. (*See* Executive Order 13211, § 2. Because EPA did not do so, the RH FIP Action is improper.

B. EPA Also Failed to Follow the Requirements of the Unfunded Mandates Reform Act.

EPA also failed to perform other necessary, regulatory analyses before issuing the RH FIP Action. The Unfunded Mandates Reform Act of 1995 ("UMRA"), Public Law 104-4, requires federal agencies to identify unfunded federal mandates in proposed legislation or regulatory processes imposing costs greater than a statutorily defined amount ($100 million) on State, local or tribal governments in the aggregate, or on the private sector. UMRA was intended to provide more information on, and prompt more careful consideration of, the costs and benefits of federal mandates that affect nonfederal parties, including private entities. 2 U.S.C. §1501. For rules that contain federal mandates, such as EPA's RH FIP Action requiring expensive pollution controls, title II of UMRA requires the agencies to prepare written statements, or "regulatory impact statements," ("RIS") containing specific descriptions and estimates, including a qualitative and quantitative assessment of the anticipated costs and benefits of the mandate. This requirement is triggered by any rule that "may result in the expenditure by State, local, and tribal governments, in the aggregate, or by the private sector, of $100,000,000 or more (adjusted annually for inflation) in any 1 year..." 2 U.S.C. §1532(a).

When this provision is triggered, the agency is specifically required to provide in a RIS several analyses, including "a qualitative and quantitative assessment of the anticipated costs and benefits of the Federal mandate, including the costs and benefits to State, local, and tribal governments or the private sector," estimates of "the future compliance costs of the Federal mandate," "any disproportionate budgetary effects of the Federal mandate upon any particular regions of the nation," and "the effect on the national economy, such as the effect on productivity, economic growth, full employment, creation of productive jobs." 2 U.S.C. § 1532(a) (emphasis added). When the written statement in Section 1532 is required, the agency is also required to "identify and consider a reasonable number of regulatory alternatives and from those alternatives select the least costly, most cost effective, or least burdensome alternative that achieves the objectives of the rule" or explain why that alternative was not selected. 2 USCA §1535 (emphasis added).

Here, EPA has failed to comply with the UMRA, arguing that the RH FIP "does not contain a federal mandate that may result in expenditures that exceed the inflation adjusted UMRA threshold of $100 million." (*See* 78 Fed. Reg. at 34,790.) EPA is wrong. As discussed above, PacifiCorp currently estimates spending more than $100 million dollars in capital cost alone in 2014 ($225 million), 2015 ($139 million), 2017 ($146 million) and 2018 ($118 million) to comply with EPA's RH FIP for Wyoming (based on alternative "one" for the Jim Bridger plant). If the regional haze compliance costs imposed by EPA's RH FIP in Arizona and EPA's approval of the Colorado RH SIP are factored in, the costs to PacifiCorp in a given year would be significantly higher. Also, when the BART NO_X and Particulate Matter ("PM") determinations are finalized by EPA for Utah, regional haze compliance costs to PacifiCorp in a given year could be much, much higher.[13] Additionally, if costs to others in the "private sector," such as the

[13] The UMRA has been applied to EPA actions where the costs to regulated entities in numerous states have been aggregated. Office of Management and Budget, "2011 Report to Congress on the Benefits and Costs of Federal Regulations and Unfunded Mandates on State, Local, and Tribal Entities (June 2011)" *available at* http://www.whitehouse.gov/omb/inforeg_regpol_reports_congress (draft Notice of Availability 76 Fed. Reg. 18,260); *see also* GAO-04-637. Based upon this precedent, PacifiCorp believes that EPA should aggregate all regional haze compliance costs across Wyoming, Utah, Colorado and Arizona for PacifiCorp, which would easily exceed the $100 million threshold. At a minimum, EPA should aggregate costs that will be incurred

cost of SCR on Basin Electric's BART Units, are added to PacifiCorp's costs, then the $100 million threshold will be exceeded by an even larger margin.

(5) EPA Improperly Proposed to Reject Wyoming's BART Determinations for NO_X which were Based on Wyoming's Thorough and Well-supported Five-factor BART Analyses.

A. Wyoming Appropriately Considered all Five BART Factors Together.

In reaching its BART determinations, Wyoming properly relied on EPA's Appendix Y Guidelines and conducted an analysis of each of the required five factors.[14] Although EPA acknowledged that "Wyoming considered all five steps above in its BART determinations," it found that Wyoming's "consideration of the costs of compliance and visibility improvement for the EGUs was inadequate and did not properly follow the requirements in the BART Guidelines and statutory requirements…"[15] Specifically, EPA noted that "because the visibility improvement associated with each of the State's control scenarios was due to the combined emission reductions associated with SO_2, NO_X, and PM controls" that "it was not possible for EPA, or any other party, to ascertain the visibility improvement that would be from an individual NO_X or PM control option."[16] *Id.* As a result, EPA proposed to disapprove the Wyoming NO_X BART determinations for certain of PacifiCorp units, and issue a RH FIP instead. However, EPA's rejection of Wyoming's BART NO_X determinations is improper for several reasons.

1. *Wyoming provided the required visibility improvement information for SCR.*

Although the various BART application analyses conducted by Wyoming for PacifiCorp's BART Units note that Wyoming conducted a "comprehensive visibility analysis covering all three visibility impairing pollutants,"[17] the analyses also state:

> "While visibility impacts were addressed in a cumulative analysis of all three pollutants, Post-Control Scenario B is directly comparable to Post-Control Scenario A as the only difference is directly attributable to the installation of

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due to EPA's FIPs in Wyoming and Arizona, which would also exceed the $100 million threshold.

[14] Appendix Y was adopted as law after notice-and-comment rulemaking (70 Fed. Reg. 39,104), and states are justified in relying on it when crafting their RH SIPs. Indeed, EPA made clear that the Appendix Y guidelines "are designed to help states and others . . . determine the level of control technology that represents BART for each source." 70 Fed. Reg. at 39,157

[15] 78 Fed. Reg. at 34,748

[16] 78 Fed. Reg. at 34,749

[17] *See, for example*, May 28, 2009, WDAQ BART Analysis for Jim Bridger at page 15; Attachment A of Wyoming 309(g) RH SIP.

> SCR. Subtracting the modeled values from each other yield the incremental visibility improvement from SCR."[18]

In other words, Wyoming clearly considered – and made available to EPA – the very specific NO_X information that EPA claims it "was not possible for EPA, or any other party, to ascertai n." Simply *claiming* it "was not possible for EPA" to ascertain results from available information does not justify EPA in rejecting Wyoming's NO_X BART determinations. Wyoming had, and considered, SCR-specific visibility information. EPA cannot use the alleged lack of this information to justify requiring SCR as BART.

2. *Wyoming's BART NO_X determinations were based on all five BART factors, including an appropriate visibility improvement assessment.*

When considering BART NO_X controls for the four BART Units at the Jim Bridger plant, Dave Johnston Units 3 and 4, and Wyodak, Wyoming properly based its BART NO_X decisions upon all BART factors in combination, including (1) costs of compliance (total capital costs and cost effectiveness), (2) power losses (energy impacts) caused by post-combustion NO_X controls and environmental considerations related to chemical reagents used with post-combustion NO_X controls (non-air quality environmental impacts), (3) existing pollution control technology in use at the source, (4) the remaining useful life of the source, and (5) visibility improvement information.[19]

In addition, Wyoming's BART NO_X determinations for the Naughton power plant further demonstrate Wyoming's consideration and balancing of all five factors, including visibility improvement, and its individualized consideration for each unit. For Naughton Units 1 and 2, Wyoming found that costs of compliance (total capital costs and cost effectiveness), power losses (energy impacts) caused by post-combustion NO_X controls, environmental considerations related to chemical reagents used with post-combustion NO_X controls (non-air quality environmental impacts), and visibility improvement information indicated that low NO_X burners ("LNBs") and over-fire air ("OFA") are BART NO_X.[20] However, for Naughton Unit 3, based upon its much greater "visibility improvement", Wyoming determined that SCR is BART NO_X. *Id.* Wyoming's BART NO_X analyses across the Naughton Plant's three units demonstrate Wyoming's consideration and weighing of all five BART factors, including the decision to require different levels of BART NO_X controls across various units at the same plant when Wyoming determined that the visibility improvements and other factors at one unit justified more stringent control. This example is yet one more indication, contrary to

[18] *Id.* at page 50

[19] *See* May 28, 2009, WDAQ BART Analysis for Jim Bridger, pages 49-50, Attachment A of Wyoming 309(g) RH SIP; May 28, 2009, WDAQ BART Analysis for Dave Johnston, pages 47-48, Attachment A of Wyoming 309(g) RH SIP; and May 28, 2009 WDAQ BART Analysis for Wyodak, pages 35-36, Attachment A of Wyoming 309(g) RH SIP; and January 7, 2011, Wyoming 309(g) RH SIP, pages 102-105 and 108-09.

[20] May 28, 2009, WDAQ BART Analysis for Naughton, pages 49-50, Attachment A of Wyoming 309(g) RH SIP.

EPA's assertions, that Wyoming did adequately consider "visibility improvement" information in each of its BART determinations, including Wyoming deciding in its discretion the "weight and significance" appropriate for each BART factor at each BART Unit.

3. Wyoming's analyses of SCR costs were not flawed.

EPA inappropriately claimed that "Wyoming's SCR capital costs on a $/kW basis often exceeded real-world industry costs"[21] and then refers to industry studies conducted between 2002 and 2007 that report installed unit capital costs actually incurred by owners broadly ranging "from $79/kW to $316/kW (2010 dollars)." *Id.* EPA also noted "instances" in its proposed RH FIP "in which Wyoming's source-based cost analyses did not follow the methods set forth in the EPA Control Cost Manual." Apart from the irony of EPA failing to follow its own Control Cost Manual as explained in Section 6 below, the information in Tables 4 and 5 shows that EPA is simply incorrect in stating that Wyoming's analyses were flawed and did not reflect real-world industry costs for the units being analyzed. These tables reflect "real-world" costs for the upcoming Jim Bridger Units 3 and 4 SCR projects, which recently were competitively bid for engineering, procurement, and construction contracts to be installed in accordance with the requirements in the Wyoming RH SIP. These real-world costs, in turn, can easily be compared to the costs assessed by Wyoming and by EPA in their BART determinations.

Table 4

Jim Bridger Unit 3 SCR Cost Assessments Comparison (LNB w/ SOFA Baseline) (excludes AFUDC)			
Project Cost Assessment	**Wyoming SIP Cost Basis***	**EPA RH FIP Cost Basis**	**Competitive Market Cost Basis**
Total Capital Costs	$153,000,000	$134,146,938	$176,129,704
Annualized Capital Costs	$14,550,300	$11,049,338	$18,740,200[22]
Annual Operating Costs	$3,370,460	$7,918,786	$2,654,500
Total Annual Cost	**$17,920,760**	**$18,968,124**	**$21,394,700**
Agency Costs versus Real-World Annual Costs (Competitive Market)	**-$3,473,940**	**-$2,426,576**	**-**

* Wyoming SIP SCR cost including AFUDC was $166,500,000 resulting in an Annualized Capital Cost of $15,839,145 and a Total Annual Cost of $19,209,605. The Wyoming SIP information presented above has been adjusted to reflect removal of an estimated $13,500,000 of AFUDC with the corresponding adjustment to Total Annual Cost for comparison purposes.

[21] *See* 78 Fed. Reg. at 34,748

[22] Assumes capital recovery factor of 10.64%; consistent with EPA Control Cost Manual Method and Andover Report cost recovery factor for comparison purposes.

Table 5

Jim Bridger Unit 4 SCR Cost Assessments Comparison (LNB w/ SOFA Baseline) (excludes AFUDC)			
Project Cost Assessment	**Wyoming SIP Cost Basis***	**EPA RH FIP Cost Basis**	**Competitive Market Cost Basis**
Total Capital Costs	$153,000,000	$112,650,287	$186,663,655
Annualized Capital Costs	$14,550,300	$9,289,920	$19,861,013[23]
Annual Operating Costs	$3,370,460	$7,255,120	$2,654,500
Total Annual Cost	**$17,920,760**	**$16,545,040**	**$22,515,513**
Agency Costs versus Real-World Annual Costs (Competitive Market)	**-$4,594,753**	**-$5,970,473**	**-**

* Wyoming SIP SCR cost including AFUDC was $166,500,00 resulting in an Annualized Capital Cost of $15,839,145 and a Total Annual Cost of $19,209,605. The Wyoming SIP information presented above has been adjusted to reflect removal of an estimated $13,500,000 of AFUDC with the corresponding adjustment to Total Annual Cost for comparison purposes.

As shown in Tables 4 and 5 above, see Attachment 3, when adjusted to exclude AFUDC as EPA argues should be done to eliminate flaws in the Wyoming RH SIP analyses, the Wyoming RH SIP cost basis aligns with EPA's RH FIP cost basis and both agencies understate the real-world costs that will be incurred on the Jim Bridger Units 3 and 4 SCR projects. For that matter, even when including AFUDC, the Wyoming RH SIP cost basis aligns closely with the EPA's cost basis, with each agency again understating real-world costs for these projects. By extension, this real-world cost information for Jim Bridger Units 3 and 4 validates the methodology used by Wyoming to determine cost information for each of PacifiCorp's BART Units. This information clearly disputes EPA's claims in its RH FIP Action that Wyoming "did not properly or reasonably take into consideration the costs of compliance" and that its SCR cost analyses exceeded real-world industry costs and were flawed. *Id.* Similar information regarding Wyoming's control technology cost analyses completed in support of the Wyoming RH SIP will be presented separately in these comments.

B. EPA Acted Illegally by Relying on "Emissions Reductions" as a Sixth BART Factor.

EPA's RH FIP Action is also illegal, arbitrary, and capricious because it relies upon factors outside of the BART five-factor analysis. Nowhere in the five-factor analysis, or anywhere in the Appendix Y Guidelines, is there any support for EPA using an "emissions reduction" factor. But this is exactly what EPA has done in its RH FIP

[23] Assumes capital recovery factor of 9.44%; consistent with EPA Control Cost Manual Method information provided with these comments.

Action. For example, EPA cited "emission reductions" as the basis for the RH FIP BART NO_X decisions for Dave Johnston Unit 3 (*See* 77 Fed. Reg. at 33,052), Wyodak (*See* 77 Fed. Reg. at 33,055) and Laramie River (*See* 77 Fed. Reg. at 33,001), among others. In doing so, however, EPA failed to account for the fact that the regional haze program is not an emissions reduction program *per se*, but is a visibility improvement program.

EPA's over-reliance on "emissions reductions" outside of the mandated BART factors has caused EPA to overstep the boundaries of the Regional Haze Program.[24] This is evidenced by the virtually non-existent visibility improvements associated with SNCR controls at Wyodak and Dave Johnston Unit 4 as required in EPA's RH FIP Action. Instead, EPA required these controls because of the associated emission reductions. Additionally, it is improper for EPA to reject Wyoming's BART determinations, which relied upon the proper balancing of all five BART factors, and replace those BART determinations with EPA's analysis, which relied upon factors outside the five-factor analysis, such as emissions reductions. (*See e.g.,* 77 Fed. Reg. at 33,052.) Courts have held that when an agency relies on factors "which Congress has not intended it to consider," then such action is arbitrary and capricious. *Arizona Public Service Co. v. US EPA,* 562 F.3d 1116, 1123 (10th Cir. 2009).

(6) <u>EPA Improperly Proposed a RH FIP Based on an Incomplete and Flawed Five-Factor BART Analyses.</u>

On June 10, 2013, EPA published its re-proposed RH FIP that was purported to be based on new information that EPA claimed had come to light and that it needed to consider. In doing so, however, EPA only attempted to reconsider two of the five BART factors: (1) costs of compliance; and (2) modeled visibility impacts. EPA's own Appendix Y Guidelines do not support evaluating individual BART factors in a vacuum, and EPA's re-proposal should have considered all new information that was available for all five BART factors when proposing a new RH FIP. BART determinations are intended to be "composite" decisions, with many facts and data from each of the five BART factors playing a role in the ultimate BART determination.[25] EPA's proposal to cherry pick one or two BART factors as a reason for rejecting Wyoming's entire NO_X BART determination for certain BART Units is arbitrary and capricious because it makes these one or two BART factors more important than any of the others, and also more important than the composite BART determination as a whole. It also disregards each of the five BART factors as Wyoming evaluated them and ignores the "weight and significance" of

[24] Additionally, EPA pays undue attention to the "health" issues in its RH FIP Action. For reasons it does not explain, EPA's RH FIP Action discusses the asserted health impacts of $PM_{2.5}$, when health impacts are not part of the BART analysis. 77 Fed. Reg. at 33,024. The Regional Haze program is not a health-based program; rather, it is focused on aesthetics. 76 Fed. Reg. 81,728, 81,752 (noting that health issues are not considered "as part of the BART determination").

[25] *Cf.* 76 Fed. Reg. at 81,733; "<u>We recognize the state's broad authority over BART determinations, and recognize the state's authority to attribute weight and significance to the statutory factors in making BART determinations</u>." (emphasis added)

each factor alone, and in combination with the others, as Wyoming determined in its BART decisions. As a result, EPA's attempt to only re-evaluate two factors leads to a RH FIP proposal that is fatally flawed. The following addresses each of the five factors that Wyoming addressed in the Wyoming RH SIP, and that EPA should have addressed in EPA's RH FIP Action.

A. First BART Factor - Costs of Compliance.

1. *EPA's development and assessment of new information is flawed and inappropriate.*

In litigation concerning the deadline by which EPA must act on the Wyoming RH SIP and in its Motion to Modify Deadlines in Consent Decree in December 10, 2012, EPA states:

> "In response to EPA's solicitation of public comments on its proposed rule, a number of commenters challenged some of the cost and visibility information provided by owners of power plants on which EPA based its proposed action. These comments prompted EPA to undertake additional research in order to evaluate the commenters' contentions. EPA developed substantial new cost and visibility analyses for several of the units subject to emission controls under the regional haze requirements. EPA is still considering this new information. EPA believes that this new information is significant and the public, including the state of Wyoming and the owners of power plants subject to regional haze requirements, should have the opportunity to comment on the new information."

A review of the "substantial new cost and visibility analyses" included by EPA in the record does not support EPA's assertion that "this new information is significant." Rather EPA has simply provided a new set of cost estimates which are primarily based upon generalized industry information regarding the installation of post-combustion NO_X controls, along with *Google Earth* satellite images available to anyone on the internet, that purportedly help assess the availability of space at each site to install retrofit emission controls. In short, the "new" information provided by EPA is not new at all, and in fact is entirely deficient for purposes of BART analyses when compared to the site-specific cost and other information prepared by utility industry experts that Wyoming utilized in its BART analyses.

EPA's new cost information is included in a report by Andover Technology Partners initially dated October 23, 2012, with an updated revision dated February 7, 2013 (the "Andover Report").[26] The Andover Report relies on algorithms in EPA's Integrated Planning Model ("IPM") to develop the total project capital costs for the SCR control systems. The IPM model is a multi-regional, dynamic, deterministic linear programming model used by EPA to evaluate the cost and emissions impacts of proposed policies to

[26] Andover Technology Partners, Review of Estimated BART Compliance Costs for Wyoming Electricity Generating Units (EGUs), February 7, 2013.

limit emissions from the electric power sector. The input to the model is generic high-level costs for various air quality control systems that can be applied to the electric power sector on a system-wide basis with minimal unit-specific information. The IPM model is not appropriate for generating site-specific cost estimates to evaluate the cost effectiveness of BART projects because it does not account for those site-specific requirements that significantly impact overall project costs. As an example of the deficiencies in the Andover Report, the following items are not reasonably accounted for in the cost estimates, particularly for the Naughton Units 1 and 2 and Dave Johnston Unit 3:

Site Elevation: Algorithms in the IPM model were developed for a generic coal-fired power plant located at or near sea level. Site elevation can have a significant impact on control system sizing and design; thus elevation of the site must be considered separately and factored into the unit capacity (i.e. megawatts) accordingly due to its effects on the flue gas volume. PacifiCorp's Wyoming BART Units are located at elevations ranging from approximately 5,000 to 7,000 feet above mean sea level ("MSL"). At this elevation, flue gas flows will be 20-30% higher than similarly sized units at MSL. The higher flue gas flow requires larger ductwork, larger reactors, and more robust support structures, and these items have a profound influence on the overall project cost. Wyoming had this information available in the Wyoming RH SIP; EPA failed to account for site elevation in its RH FIP Action.

Site-specific Congestion and Construction Challenges: The IPM model applies a retrofit factor to account for the difficulty of fitting new BART equipment into the existing site configuration. The Andover Report states that site visits were not possible; thus, retrofit factors for Naughton Units 1 and 2, and Dave Johnston Unit 3 were determined based on a review of Google Earth images of the station. Accordingly, the Andover Report applied retrofit factors for the units that are highly subjective based on minimal site information. When preparing site-specific cost estimates, however site walkdowns must be conducted to evaluate the true complexity associated with the retrofit and assess specific modifications to the plant that would be required to overcome issues associated with congestion as well as difficulties associated with construction. Neither Andover nor EPA sought permission from PacifiCorp to visit the sites of the BART Units, nor did Andover explain it "wasn't possible" to do so. Both Sargent & Lundy ("S&L") and Babock and Wilcox ("B&W") have extensive experience with PacifiCorp's Naughton and Dave Johnston facilities. Just since 2005, S&L has been contracted by PacifiCorp to perform 14 projects at Dave Johnston station and over 25 projects at Naughton station. These projects range from site evaluations, studies, detailed engineering, or functioning as PacifiCorp's Owner's Engineer for major environmental retrofit engineer, procure, and construct ("EPC") projects. From having conducted many walkdowns at these stations, S&L is very aware of site- specific congestion and construction challenges that would affect SCR installations at Naughton 1, Naughton 2, and Dave Johnston 3. Similar to S&L's site specific experience, B&W has recently completed major environmental retrofit EPC projects on Naughton Units 1 and 2 (wet scrubber additions) and Dave Johnston Unit 3 (dry scrubber and baghouse addition), making B&W uniquely positioned to offer budgetary cost estimates for further retrofits to those facilities with significant first-hand knowledge. Wyoming had much of this information available in the Wyoming RH SIP; EPA failed to account for site-specific information in its RH FIP Action

Missing Scope Items: Additional project-specific scope concerns (related to addition of SCR onsite) include limited capacity of the existing induced-draft ("ID") fans and auxiliary power system, as well as National Fire Protection Association ("NFPA") related equipment reinforcement requirements. Larger, more powerful, ID fans may overload existing electrical systems, and the electrical systems may require significant modifications. Structural stiffening of the duct work, and equipment downstream of the boiler and upstream of the new ID fans may also be required by NFPA regulations to operate at more negative pressures due to the installation of the SCR. These types of costs are not generally reflected in the base case IPM cost algorithms, but they must be taken into consideration in the development of a project-specific cost estimate. Wyoming had this information available in the Wyoming RH SIP; EPA failed to account for this important cost information in its RH FIP Action.

Owner's Costs: Worksheets attached to the Andover Report[27] show that Owner's Costs were inappropriately excluded from the Andover Report's capital cost estimate. Owner's Costs include a variety of non-financial costs incurred by the owner to support implementation of the air pollution control project. Owner's Costs are project-specific, but generally include costs incurred by the owner to manage the project, hire and retain staff to support the project, and costs associated with third party assistance associated with project development and financing. Owner's Costs include, but may not necessarily be limited to:

- site investigations (geotechnical, hydrology, etc.) for project design;
- environmental permitting/approvals;
- insurance during construction;
- site security during construction;
- transmission interconnection (if applicable);
- fuel interconnection (if applicable);
- owner's mobilization costs;
- owner's project management and support staff;
- insurance advisor;
- labor relations consultant;
- tax consultant;
- financial advisor;
- legal advisor;
- market consultant; and
- community relations/community outreach program.

Owner's Costs are real costs that the owner will incur during the project and are typically included in cost estimates prepared for large air pollution control retrofit projects. In fact, U.S. EPA's Coal Quality Environmental Cost (CUECost) model includes Owner's Costs

[27] See, EPA-R08-OAR-2012-0026-0085 and -0087 for examples.

(or “Home Office” costs) in its air pollution control system cost estimating workbook and interrelated set of spreadsheets.[28] Wyoming had this information available in the Wyoming RH SIP; EPA failed to account for this important cost information in its RH FIP Action.

Regional Labor: Regional labor concerns are not accounted for in the IPM model. Regional labor characteristics must be taken into consideration in a site-specific cost estimate to account for factors including labor availability, project complexity, local climate and working conditions. Because the Naughton and Dave Johnston facilities are in relatively remote locations, higher labor rates must be paid to attract the kind of skilled workers required to construct an SCR project. In addition, the locations are subject to extreme cold and wind that can result in significant productivity and construction challenges and delays, adding to the overall project cost. Wyoming had this information available in the Wyoming RH SIP; EPA failed to account for this important cost information in its RH FIP Action.

As noted above, EPA’s flawed analyses of incomplete “new” cost information directly resulted in EPA’s proposed requirements for PacifiCorp to install SCR on Naughton Units 1 and 2 and Dave Johnston Unit 3. In contrast, to be responsive to EPA’s request for additional information, PacifiCorp has solicited budgetary project-specific cost information from B&W, an active and uniquely positioned competitive market participant for SCR technology, for these same units. In conjunction with S&L’s expertise, PacifiCorp has incorporated the site-specific budgetary cost information from B&W into updated EPA Control Cost Manual side-by-side comparisons with the Andover Report results to further demonstrate the inaccuracies in the new cost information developed by EPA. The following Tables 6 through 8 summarize the results of these comparisons, to these comments provides the detailed line-by-line cost manual method comparisons. It is important to note that PacifiCorp has utilized a 20-year remaining equipment life and has excluded AFUDC from the results in the following tables for comparison purposes. Remaining equipment life and AFUDC will be addressed separately in comments below. *(See* Attachment 4*)*

[28] See, Coal Utility Environmental Cost (CUECost) Workbook User’s Manual Version 1.0, prepared by Raytheon Engineers & Contractors, Inc. and Eastern Research Group, Inc., EPA Contract No. 68-D7-0001, Appendix B, pages B-3 and B-6.

Table 6

Naughton Unit 1 SCR Cost Assessment Retrofit Factor versus Project Specific Assessment (20-year life, excludes AFUDC)		
SCR Cost Assessment	**EPA Cost Manual Method** Andover IPM/Retrofit Factor Approach	**EPA Cost Manual Method** PacifiCorp Project Specific Approach
Total Direct Annual Cost	$1,820,054	$3,148,690
Total Indirect Annual Cost	$4,692,935	$8,855,555
Total Annual Cost	$6,504,803	$12,004,246
Annual NO_x Tons Removed	1,109	1,109
Cost Effectiveness ($/ton)	**$5,867**	**$10,824**

Table 7

Naughton Unit 2 SCR Cost Assessment Retrofit Factor versus Project Specific Assessment (20-year life, excludes AFUDC)		
SCR Cost Assessment	**EPA Cost Manual Method** Andover IPM/Retrofit Factor Approach	**EPA Cost Manual Method** PacifiCorp Project Specific Approach
Total Direct Annual Cost	$1,597,635	$3,474,571
Total Indirect Annual Cost	$5,814,581	$8,802,316
Total Annual Cost	$7,959,487	$12,276,887
Annual NO_x Tons Removed	1,336	1,336
Cost Effectiveness ($/ton)	**$5,956**	**$9,189**

Table 8

Dave Johnston Unit 3 SCR Cost Assessment Retrofit Factor versus Project Specific Assessment (20-year life, excludes AFUDC)		
SCR Cost Assessment	**EPA Cost Manual Method** Andover IPM/Retrofit Factor Approach	**EPA Cost Manual Method** PacifiCorp Project Specific Approach
Total Direct Annual Cost	$2,398,216	$3,884,089
Total Indirect Annual Cost	$7,158,911	$9,601,020
Total Annual Cost	$9,562,381	$13,485,109
Annual NO_x Tons Removed	1,597	1,597
Cost Effectiveness ($/ton)	**$5,989**	**$8,444**

As demonstrated by the results in the tables above, EPA significantly understated costs per ton of pollutant removed. As such, EPA based its cost effectiveness conclusions on significantly inaccurate information. Before taking any final action on the proposed RH FIP, EPA must consider in its final BART analyses the additional cost information being provided by PacifiCorp. (*See* Attachment 4)

2. *EPA's dismissal of owners costs and AFUDC is inappropriate.*

EPA states in its RH FIP Action:[29]

> "For all control technologies, EPA has identified instances in which Wyoming's source-based cost analyses did not follow the methods set forth in the EPA Control Cost Manual. For example, Wyoming included an allowance for funds used during construction and for owners costs and did not provide sufficient documentation such as vendor estimates or bids."

With respect to AFUDC, another utility (OG&E) argued in a similar regional haze setting that:

> "AFUDC provides a way of measuring the real cost of interest over the construction period. AFUDC accounts for the time value of money associated with the distribution of construction cash flows over the construction period, which may be approximately 18 months for an SCR project. TCI, as defined in the *Control Cost Manual*, includes all costs required to purchase equipment needed for the control system (purchased equipment costs), the costs of labor and materials for installing that equipment (direct installation costs), costs for site preparation and building, working capital, and off-site facilities.[30]

[29] See, 78 Fed. Reg. at 34,749

[30] *Control Cost Manual*, page 2-5.

A cost breakdown of TCI (as defined above) is presented in several examples in the *Control Cost Manual*. For example, Table 1.4 (page 1-32 of Section 4 – NO_X Controls) and Table 2.5 (page 2-44 of Section 4 – NO_X Controls) therein explicitly identify AFUDC as component "E" of the TCI, where TCI = D + E + F + G + H + I, where:

D = Total Plant Cost
E = AFUDC
F = Royalty Allowance
G = Preproduction Cost
H = Inventory Capital
I = Initial Catalyst and Chemicals

References 9 and 10 on page 2-38 of the *Control Cost Manual* explicitly include AFUDC as a cost component and reference two reports, by Shattuck and Kaplan, in support of its use.[31] [32] The report by Shattuck was published in connection with an EPRI funded research project and cost estimating software for FGD retrofits. The report by Kaplan was published by the EPA, Air and Energy Engineering Research Laboratory, in collaboration with EPRI, the U.S. Department of Energy, and an industry technical advisory committee represented by seven major utility companies. These FGD cost studies were developed from the most comprehensive industry experience of the late 1980's and early 1990's. The EPA built upon this knowledge base and costing methodology in its publication of the *Control Cost Manual* in 2002. Thus, the *Control Cost Manual* allows the time value of money, measured by the real discount rate, to be incorporated into the cost estimate.

Section 2.3.1 of the *Control Cost Manual* (Elements of Total Capital Investment) describes the need for TCI to include all expenditures incurred during the construction phase of the project, including direct costs, indirect costs, fuel and consumables expended during start-up and testing, and other capitalized expenses. The only items explicitly mentioned to be excluded are common facilities that already exist at the site. AFUDC is part of the expense that will be incurred with the installation of a large air pollution control system, and the accepted practice in the utility industry and by financial institutions is to treat AFUDC as a capitalized expenditure. This approach is recognized in publications by the U.S. Department of Energy – Energy Information Administration (DOE/EIA), such as the *Annual Energy Outlook,*[33] and in publications by the Electric Power Research Institute (EPRI), such as the *Technical Assessment Guide*.[34] As previously mentioned, the EPA clearly

[31] Shattuck, D. M., et al., Retrofit FGD Cost-Estimating Guidelines, Electric Power Research Institute, Palo Alto, CA (CS-3696, Research Project 1610-1), October 1984.
[32] Kaplan, N., et al., "Retrofit Costs of SO2 and NOx Control at 200 U.S. Coal-Fired Power Plants," Pittsburgh Coal Conference, 1990.
[33] See, DOE/EIA-0383 (2011), March 2011.
[34] See, *TAG Technical Assessment Guide*, EPRI, page 2-15.

followed this approach in its studies of retrofit costs of SO_2 and NO_X in the years leading up to its publication of the *Control Cost Manual*. Furthermore, AFUDC has been included in several other coal-fired boiler BART determinations, and AFUDC is included as a line item in EPA's CUECost worksheets for FGD control systems.[35] In cases where the time value of money during the construction period would be significant (e.g., projects with longer construction periods such as the installation of SCR or FGD), the *Control Cost Manual* clearly allows inclusion of AFUDC."[36]

PacifiCorp supports and adopts by reference OG&E's argument regarding including AFUDC in project cost estimates. Whether or not AFUDC is included in project cost estimates does not materially impact the results reached under the EPA Control Cost Manual method, its inclusion should not constitute a basis for EPA to reject Wyoming's entire cost assessments. Tables 9 through 11 provide comparisons of PacifiCorp's project specific EPA Control Cost Manual method results where AFUDC is excluded in one set of costs and is included in the other to demonstrate this point. Attachment 4 to these comments provides the detailed line-by-line Control Cost Manual method comparisons.

Table 9

Naughton Unit 1 SCR Cost Assessment Impact of AFUDC on Project Specific Assessment		
SCR Cost Assessment	**EPA Cost Manual Method** PacifiCorp Project Specific Approach (excludes AFUDC)	**EPA Cost Manual Method** PacifiCorp Project Specific Approach (includes AFUDC)
Total Direct Annual Cost	$3,148,690	$3,368,040
Total Indirect Annual Cost	$8,855,555	$9,683,759
Total Annual Cost	$12,004,246	$13,051,799
Annual NO_x Tons Removed	1,109	1,109
Cost Effectiveness ($/ton)	**$10,824**	**$11,769**
Effect of AFUDC on Cost Effectiveness ($/ton)		**$945**

[35] Coal Utility Environmental Cost (CUECost) Worksheets, prepared by Raytheon Engineers & Contractors, Inc. and Easter Research Group, Inc., EPA Contract No. 68-D7-001.

[36] Docket EPA-R06- OAR-2010-0190

Table 10

Naughton Unit 2 SCR Cost Assessment Impact of AFUDC on Project Specific Assessment		
SCR Cost Assessment	**EPA Cost Manual Method** PacifiCorp Project Specific Approach (excludes AFUDC)	**EPA Cost Manual Method** PacifiCorp Project Specific Approach (includes AFUDC)
Total Direct Annual Cost	$3,474,571	$3,692,696
Total Indirect Annual Cost	$8,802,316	$9,625,894
Total Annual Cost	$12,276,887	$13,318,590
Annual NO_x Tons Removed	1,336	1,336
Cost Effectiveness ($/ton)	**$9,189**	**$9,969**
Effect of AFUDC on Cost Effectiveness ($/ton)		**$780**

Table 11

Dave Johnston Unit 3 SCR Cost Assessment Impact of AFUDC on Project Specific Assessment		
SCR Cost Assessment	**EPA Cost Manual Method** PacifiCorp Project Specific Approach (excludes AFUDC)	**EPA Cost Manual Method** PacifiCorp Project Specific Approach (includes AFUDC)
Total Direct Annual Cost	$3,884,089	$4,122,064
Total Indirect Annual Cost	$9,601,020	$10,499,546
Total Annual Cost	$13,485,109	$14,621,610
Annual NO_x Tons Removed	1,597	1,597
Cost Effectiveness ($/ton)	**$8,444**	**$9,156**
Effect of AFUDC on Cost Effectiveness ($/ton)		**$712**

3. EPA's dismissal of Wyoming's results due to lack of appropriate documentation such as vendor estimates or bids is inappropriate.

EPA's RH FIP Action also is flawed because it failed to provide sufficient documentation such as vendor estimates or bids to validate its estimates. EPA attempts to justify its approach by stating: [37]

> "In our revised cost analyses, we have followed the *structure* (emphasis added) of the EPA Control Cost Manual, though we have largely used the Integrated Planning Model cost calculations to estimate direct capital costs and operating and maintenance costs."

EPA did not explain what it meant by following the "structure" of the manual, versus simply following the manual. By contrast, PacifiCorp solicited and incorporated vendor estimates into these comments. This new information, which EPA must incorporate into new BART analyses to the extent EPA issues a final RH FIP, validates the state of Wyoming's BART analyses cost of controls estimates. In addition, it further quantifies the inaccuracies in EPA's development and use of purported new information that in no way qualifies as vendor estimates, bids, or any type of site specific vendor information.

B. Second BART Factor - Energy and Non-Air Quality Environmental Impacts of Compliance.

EPA's RH FIP Action is also defective because EPA failed to evaluate the "energy" and "non-air quality environmental" factors for the BART Units. Therefore, even if EPA were correct that Wyoming performed an improper BART analysis (which it is not) EPA's RH FIP Action is based upon an incorrect BART analysis because it fails to take into account this BART factor.

Three types of energy impacts should be considered. These include the energy associated with operating the controls, the energy that must be provided when the unit is removed from service in order to install the controls, and most importantly to the state of Wyoming and its citizens, the energy that must be replaced when the emissions controls prescribed for a given unit are not economically justifiable and result in accelerated unit retirements and replacements. [38]

The latter scenario is of particular concern because the EPA has now proposed SCR controls for PacifiCorp's Naughton Unit 1, Naughton Unit 2 and Dave Johnston Unit 3. Unlike the Wyoming RH SIP, the EPA's RH FIP requires controls that are not expected to be justifiable and would result in accelerated unit retirements and replacements, potential natural gas conversions, and the associated costs and socio-economic impacts of removing major coal-fueled generation resources from service in areas of Wyoming that rely heavily on these facilities.

[37] 78 Fed. Reg. at 34,749

[38] 40 CFR 50 Appendix Y D.IV.h.5

EPA's five-factor analysis must include a thorough analysis of the system-wide energy impacts individual unit compliance requirements will have on the states within which PacifiCorp serves customers, including the impacts to local jobs and state and local economies surrounding the affected facilities. EPA's analysis is incomplete and conclusions are flawed if these significant additional costs are not developed and considered.

EPA's energy impacts assessment should include coordination with state regulators, environmental agencies and elected officials. As a regulated utility, PacifiCorp regularly engages with state regulators, environmental agencies and elected officials to ensure that its resource planning and ultimate compliance approaches align with the interests of customers in the states it serves. These same state bodies and elected officials should be consulted by EPA to ensure that EPA's RH FIP Action is properly assessed in light of the issues described above.

As Powder River Basin Resource Council pointed out in its post-hearing brief filed in April 2013 before the Wyoming Public Service Commission in PacifiCorp's application filing to obtain approval for a Certificate of Public Convenience and Necessity to Construct Selective Catalytic Reduction systems on Jim Bridger Units 3 and 4, "it is evident that considering the cost and risk of these major environmental control projects up front, prior to installation, is a benefit to parties, ratepayers, and the public interest. These projects are significant undertakings – in some cases they are close to the financial equivalent of building new generation sources – and therefore they deserve a high level of scrutiny to ensure that the public's interests, and especially the specific financial interests of PacifiCorp ratepayers, are protected."[39]

PacifiCorp is required to obtain approval of its environmental plans and expenditures; regardless of EPA's position, the utility regulatory commissions are required to find that the installation of emission controls are necessary, used and useful, and the least-cost, risk adjusted alternative to comply with environmental regulations. While it is likely parties will take the position on EPA's proposed action in this docket that stringent controls and emission rates should be installed as quickly as possible without regard to system impacts and cost, their positions in other dockets have been that PacifiCorp should not install emissions controls because doing so "result[ed] in unnecessary capital expenses that were not the least cost alternative."[40]

[39] See Powder River Basin Resource Council's Post-Hearing Brief in Wyoming Public Service Commission Docket No. 20000-418-EA-12 (RECORD NO. 13314) at: http://edocs.puc.state.or.us/AD9EAE92- D6A8-4C0E-81D1-DB442CFB2244/FinalDownload/DownloadId-DCE8BAB12B5061CB4017455D76704E32/AD9EAE92- D6A8-4C0E-81D1-DB442CFB2244/efdocs/HBC/ue246hbc75023.pdf

[40] See Sierra Club's prehearing brief in Oregon Public Utility Commission Docket UE 246 at: http://edocs.puc.state.or.us/AD9EAE92-D6A8-4C0E-81D1-DB442CFB2244/FinalDownload/DownloadId-DCE8BAB12B5061CB4017455D76704E32/AD9EAE92- D6A8-4C0E-81D1-DB442CFB2244/efdocs/HBC/ue246hbc75023.pdf

EPA must consider that its proposed RH FIP will "result in significant economic disruption and unemployment" due to accelerated unit retirements and replacements, potential natural gas conversion and removing coal-fired units from service.[41]

C. Third BART Factor - Any Existing Pollution Control Technology in Use at the Source Must be Considered.

In proposing the RH FIP based on its own BART analyses, EPA must evaluate current information, including all significant parameters that have changed since Wyoming completed its BART analyses. Specifically, EPA should take into account that, with the exception of Naughton Unit 3, PacifiCorp has installed and fully implemented the BART controls required under Wyoming's RH SIP. Some of this information was not available, or conditions have substantially changed, since Wyoming completed the Wyoming RH SIP. Table 1 in the "HISTORY OF THE WYOMING RH SIP" section identifies the controls that have been installed at each of PacifiCorp's BART Units in Wyoming.

EPA's RH FIP Action must take into account both the control equipment currently installed and operating on the BART Units as well as each unit's current emissions baseline. It is not appropriate for EPA to continue using a 2001-2003 emissions baseline that does not recognize the controls that have been installed. This is particularly relevant because EPA partially rejected Wyoming RH SIP, and then conducted its own BART analyses in 2013 based on "new information." EPA is well aware of the controls that PacifiCorp has installed in compliance with the Wyoming RH SIP, and in fact, utilized recent NO_X emission rates from PacifiCorp's units that are equipped with BART controls in order to identify appropriate SNCR rates in regard to its RH FIP Action.

To properly assess the visibility and costs associated with adding additional controls, EPA's BART analyses must take into account the control equipment currently operating on these BART Units. Both the annual NO_X emissions used in the cost effectiveness calculations and the hourly NO_X emissions used in the visibility modeling must be corrected to reflect the LNB/OFA controls currently in service on PacifiCorp's BART-eligible units.

D. Fourth BART Factor - The Remaining Useful Life of the Source.

PacifiCorp submitted its BART studies to Wyoming in 2007, and the state completed its BART analyses during 2008. At that time the remaining useful life of all PacifiCorp BART Units was considered to be at least 20 years. Primarily due to EPA's delays in dealing with the Wyoming RH SIP, this assumed twenty-year life span is no longer a valid basis for certain units. EPA now must take into account the current useful life of the units, rather than the useful life assumed under Wyoming's BART analyses completed at

[41] 78 Fed. Reg. at 34,749

a different point in time. Dave Johnston Unit 3's current depreciable life ends in 2027 and the life for Naughton Units 1 and 2 ends in 2029.

As a practical matter, the SCRs required under the RH FIP at Dave Johnston Unit 3 and Naughton Units 1 and 2 could not be installed until shortly before the end of 2018, due to the regulatory processes that apply to PacifiCorp's major investment decisions, as well as the associated permitting and competitive procurement timelines. Attachment 5 provides a general description of such a timeline. At that time, the useful life for Dave Johnston Unit 3 will be nine years, and for Naughton Unit 1 and 2 eleven years. EPA must use these shorter useful lives in its BART analyses. Tables 12 through 14 summarize the cost effectiveness results assuming the proper useful lives of these units, and Attachment 4 to these comments provides the detailed line-by-line cost manual method comparisons.

Table 12

Naughton Unit 1 SCR Cost Assessment Retrofit Factor versus Project Specific Assessment Remaining Depreciable Life Basis (excludes AFUDC)		
SCR Cost Assessment	**EPA Cost Manual Method** Andover IPM/Retrofit Factor Approach	**EPA Cost Manual Method** PacifiCorp Project Specific Approach
Total Direct Annual Cost	$1,820,054	$3,148,690
Total Indirect Annual Cost	$6,413,089	$12,510,995
Total Annual Cost	$8,233,143	$15,659,686
Annual NO_x Tons Removed	1,109	1,109
Cost Effectiveness ($/ton)	**$7,424**	**$14,121**

Table 13

Naughton Unit 2 SCR Cost Assessment Retrofit Factor versus Project Specific Assessment Remaining Depreciable Life Basis (excludes AFUDC)		
SCR Cost Assessment	**EPA Cost Manual Method** Andover IPM/Retrofit Factor Approach	**EPA Cost Manual Method** PacifiCorp Project Specific Approach
Total Direct Annual Cost	$1,597,635	$3,474,571
Total Indirect Annual Cost	$7,945,865	$12,435,779
Total Annual Cost	$9,543,500	$15,910,351
Annual NO_x Tons Removed	1,336	1,336
Cost Effectiveness ($/ton)	**$7,143**	**$11,909**

Table 14

Dave Johnston Unit 3 SCR Cost Assessment Retrofit Factor versus Project Specific Assessment Remaining Depreciable Life Basis (excludes AFUDC)		
SCR Cost Assessment	**EPA Cost Manual Method** Andover IPM/Retrofit Factor Approach	**EPA Cost Manual Method** PacifiCorp Project Specific Approach
Total Direct Annual Cost	$2,398,216	$3,884,089
Total Indirect Annual Cost	$11,135,336	$15,611,622
Total Annual Cost	$13,533,552	$19,495,711
Annual NO_x Tons Removed	1,597	1,597
Cost Effectiveness ($/ton)	**$8,474**	**$12,208**

Taking into consideration the remaining useful lives of these particular BART Units clearly demonstrates that EPA's current assessed cost effectiveness conclusions (whether using the Andover Report costs or PacifiCorp's updated information) do not support the installation of SCR on these units because they are not cost effective. To the extent EPA needs to include firm retirement dates commensurate with the depreciable lives for purposes of finalizing the RH FIP, then PacifiCorp requests that EPA do so.

E. The Fifth BART Factor - The Degree of Visibility Improvement which may Reasonably be Anticipated from the use of BART.

Finally, EPA's RH FIP Action must appropriately consider new information provided by PacifiCorp and others associated with visibility modeling. In comments provided in response to EPA's first proposal, PacifiCorp presented substantial information supporting the need to use improved and updated versions of the computer models used to predict visibility impacts. In addition, PacifiCorp provided substantial information on the effects that the nitrogen oxides to nitrogen dioxide conversion rate and background ammonia concentrations have on modeled visibility impacts. EPA's RH FIP Action is not complete without taking into account this new information about visibility. In particular, given that EPA has re-proposed its RH FIP based on cost and visibility information from certain groups, EPA should analyze and incorporate PacifiCorp's data in the same way.

Computerized air quality modeling plays two key roles in the regional haze program. First, unit-by-unit CALPUFF modeling is conducted to determine which BART-eligible units should be subject to BART [42]. Wyoming determined that a source modeled to impact a Class I area by more than 0.5 deciviews was subject to BART and required to conduct a BART analysis.

The unit-specific CALPUFF modeling results that EPA uses in its RH FIP Action do not provide the degree of visibility improvement that can be reasonably anticipated from the use of BART at a specific unit. Regional models that take into account all emission changes from all emissions sources are used for this purpose. EPA's reliance on miniscule modeled visibility improvements conducted at individual BART Units ignores the fact that (1) such small visibility improvements are not perceptible to the human eye, (2) CALPUFF modeling results are unreliable, imprecise, and over-predictive, especially when older versions of the model are used, and (3) the modeled improvements occur over just a few days per year. In other words, although running the computer models does create a predicted visibility outcome, it does not provide an outcome that qualifies as "reasonably anticipated."

EPA treats the results from computerized visibility modeling as being capable of accurately predicting visibility improvements down to the tenths or hundredths of a deciview (when one deciview is considered what is humanly perceptible). For example, EPA assumes that a difference of 0.1 or 0.2 deciviews between its model results and Wyoming's model results is material. It is not. The reality is that these computer models, including CALPUFF, are relatively imprecise. The inherent problems and limitations of the computerized visibility modeling EPA used here should be considered as part of EPA's BART determinations, but were not. Outlined below are the problems and

[42] 40 CFR Part 51 Appendix Y, III. How to Identify Sources "Subject to BART"

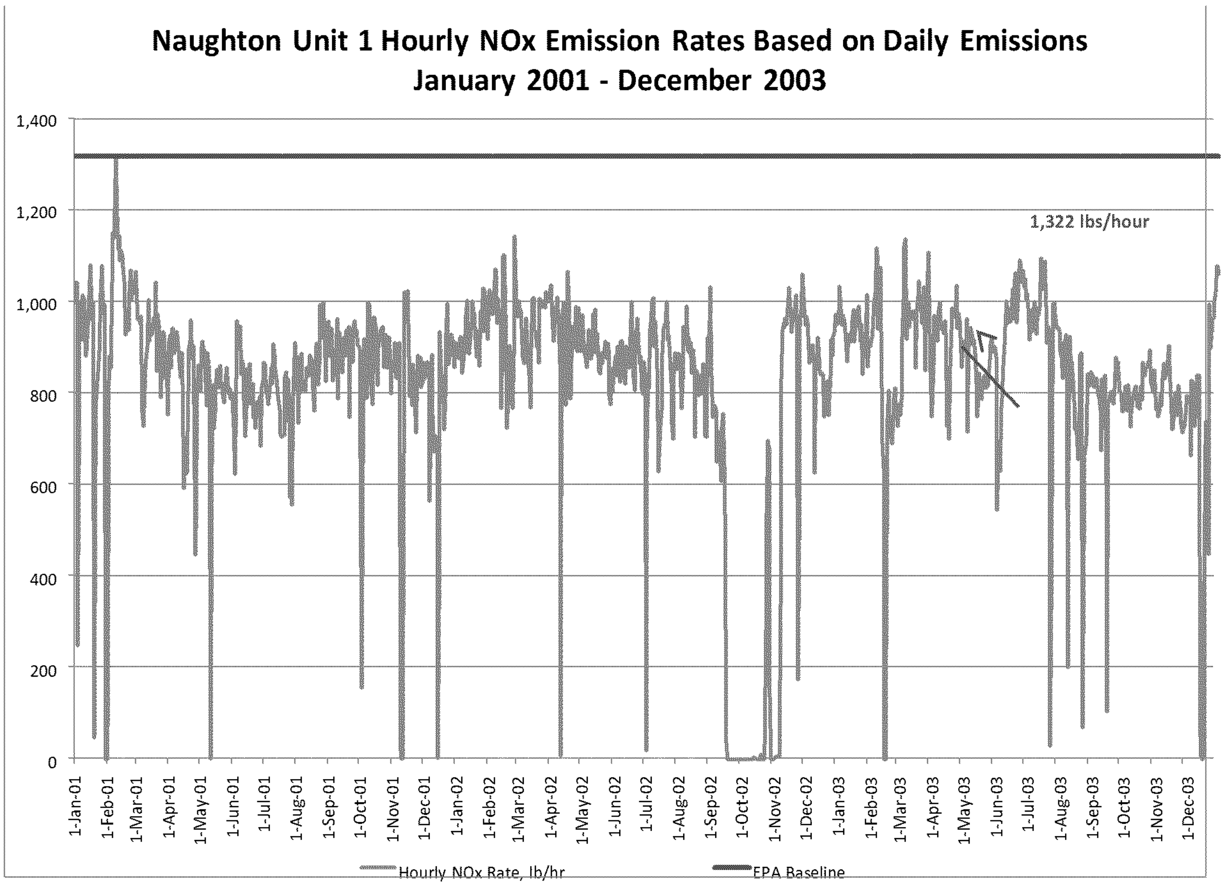
limitations with EPA's computerized modeling. EPA should redo its computer modeling, and reanalyze its modeling results, after taking these issues into account.

i) EPA's 2001-2003 baseline over-predicts the modeled visibility impacts and improvements

In its modeling, EPA created a baseline emission rate using the maximum 24-hour emission rate that occurred during the 2001-2003 period. This rate is then used in the CALPUFF models as if it occurs every hour of every day over the three-year period.

Chart 1, which is specific to Naughton Unit 1, provides a visual comparison of the baseline rate used by EPA to predict the visibility impacts to the actual emissions from this unit over the three-year time period. Noting the significant over-projection of emissions over the entire time period, it is unrealistic to imply that the model can be used to identify the visibility impacts and in turn, the visibility improvements that may reasonably be anticipated . At a minimum, EPA must recognize that CALPUFF's results will over predict improvements and will not lead to result s that can be "reasonably anticipated" as compared to actual visibility improvement.

CHART 1



Similar charts for each of PacifiCorp's Wyoming units have been provided in Attachment 6.

In its BART determinations, Wyoming has balanced the modeling inputs and results against the criteria of what visibility improvement can be reasonably anticipated to occur. EPA's RH FIP Action, however, improperly focuses solely on the modeling results without accounting for whether its models reasonably anticipate the visibility impacts will occur.

ii) EPA's use of 2001-2003 historic emissions does not account for the controls that are currently installed and operating on PacifiCorp's units

Any existing pollution control technology in use at the source must be considered [43], and using historic emissions from a 10+ year old time period (2001-2003) to establish each unit's baseline emission rate is inappropriate. With the exception of Naughton Unit 3 and Dave Johnston Unit 1 and Unit 2, from 2005-2012 Low NO_X burners have been installed on every PacifiCorp coal-fueled unit in Wyoming. While EPA relies on recent historic unit emission data to predict and propose SNCR NO_X emissions rates, it improperly fails to recognize that the baseline visibility modeling also must be based on the current hourly emission rates of the units. EPA has recognized the need to adopt baseline emissions that reflect the installation of existing pollution control equipment. 77 Fed. Reg. at 72,526; 78 Fed. Reg. at 46,163. EPA should do so here.

iii) EPA has relied upon modeling that is out of date and does not meet EPA's own requirements.

Proper conclusions can be reached when evaluating the results of visibility modeling if one understands the limitations of the models, the characteristics and limitations of the inputs entered into the models, the capabilities of the model versions being used and then apply reasonable judgment to the results. Wyoming has conducted its RH SIP based on the modeling protocols and versions available at the time its RH SIP was completed. Because of this, there are limitations associated with the results obtained. However, in proposing its RH SIP, Wyoming has evaluated the model output with an understanding of the model's limitations. Wyoming then applied its judgment, as encouraged and required by EPA's guidelines and the CAA, which helped to mitigate the issues associated with models that over-predict the visibility improvement associated with BART controls being added.

Contrary to this approach EPA interprets the modeling results as an "absolute" and unquestioningly accurate number that it then relies on in an attempt to justify costly BART controls that in reality will provide no perceptible visible benefit. EPA gives no consideration to the limitations of the models it uses. In the absence of using good

[43] 40 CFR 51, Appendix Y. IV.A(2)

judgment to deal with over-predictive results, it is critical that EPA use the most up-to-date and scientifically accurate models available. The following comments are intended to provide insight into the limitations of specific models and encourage EPA to either recognize the limitations of the models that have been used in Wyoming or utilize the models that represent the best science available.

PacifiCorp and Wyoming originally conducted CALPUFF modeling in 2006-07 to determine which of PacifiCorp's units were "BART-eligible." In accordance with EPA guidance at the time, PacifiCorp and Wyoming used the CALPUFF model, Version 5.711a, with a background ammonia setting of 2 parts per billion ("ppb") and Method 6 of CALPOST. After this modeling was completed, EPA formally adopted CALPUFF Version 5.8 as the "approved version" of CALPUFF, and determined that Method 8 of CALPOST should be used. EPA also stated several times since 2007 that the background ammonia concentration used in CALPUFF modeling in the Intermountain West should be 1 ppb.

Since the time PacifiCorp and Wyoming conducted its CALPUFF modeling in 2006-07, air quality modeling has improved. Air modeling experts now have determined that CALPUFF version 6.42, with a variable ammonia background setting, updated chemistry module, and Method 8 of CALPOST are the "best" science when it comes to modeling for regional haze. However, EPA did not use the "best" modeling science in Wyoming, even when taking the extra time to re-propose its RH FIP based on new information. Instead, EPA used outdated and unreliable modeling techniques.

EPA's reliance upon its outdated modeling method is arbitrary and capricious because EPA's modeling fails to meet EPA's own standards, ignores the best science, and does not account for CALPUFF's tendency to overestimate results (i.e., visibility improvements).

1. *EPA's re-proposal, which was intended to update its conclusions based on new information, should have used the most recent version of CALPUFF, or at a minimum, should have used the version that EPA requires for other RH SIPs.*

EPA has taken the position that CALPUFF Version 5.8 must be used for regional haze modeling. For example, in regard to the Arizona RH SIP, EPA recently stated as follows:

> <u>"EPA relied on version 5.8 of CALPUFF because it is the EPA-approved version promulgated in the Guideline on Air Quality Models</u> (40 CFR part 51, Appendix W, section 6.2.1.e; 68 FR 18440, April 15, 2003). It was also the approved version when EPA promulgated the BART Guidelines (70 FR 39122, July 6, 2005). EPA updated the specific version to be used for regulatory purposes on June 29, 2007, including minor revisions as of that date; the approved CALPUFF modeling system includes CALPUFF version 5.8, level 070623, and CALMET version 5.8 level 070623. At this time, <u>any other version of the CALPUFF modeling system would be considered an</u>

> "alternative model", subject to the provisions of Guideline on Air Quality Models section 3.2.2(b), requiring a full theoretical and performance evaluation."

77 Fed. Reg. 42,834, 42,854 (emphasis added). However, EPA's unit-specific CALPUFF modeling in Wyoming initially completed in April 2012 and redone in February 2013, used CALPUFF Version 5.711a (originally released in 2004). (*See* Attachment 7, CH2M Hill Report on EPA Modeling Methods.) Version 5.711a is nine years old, and several CALPUFF versions behind Version 5.8. While PacifiCorp believes the more modern and realistic CALPUFF Version 6.42 should be used (see below), at a minimum EPA must abide by its own position and use Version 5.8 in evaluating the Wyoming RH SIP, which it failed to do. According to EPA's own statements, EPA's chosen modeling results should be discarded because EPA used an improper "alternative model" in Wyoming.

Moreover, EPA should have used the most recent version of CALPUFF (Version 6.42) in Wyoming because it produces more realistic and accurate results. (*See* Attachment 8, Paine, B, Connors, J, "Response to Prehearing Statements: Martin Drake Power Plant Best Available Retrofit Technology Rulemaking Hearing," November 20, 2010.) Version 6.42 contains needed refinements, such as a better "chemistry" module known as ISORROPIA (Version 2.1). *Id.* CALPUFF Version 6.42 is more accurate because, as the Federal Land Managers (FLMs) have noted, Version 5.8 does not have the required settings to perform the new Method 8 visibility analysis. (*See* Attachment 9, March 21, 2012 letter from Joe Scirie to Bill Lawson.)

Additionally, CALPUFF Version 6.42 has been maintained by TRC and has had many bug fixes and enhancements not included in CALPUFF Version 5.8. *Id.* Most importantly, the previous chemistry modules used in Version 5.8 (and in the 5.711a Version EPA used here) also have been shown to overestimate nitrate concentrations in Wyoming by a factor of 3-4 and substantial improvements have been made to eliminate this over-prediction using the ISORROPIA module. *Id.*; (*see also* Attachment 10, Scire, J., Strimaitis, D., and Zhong-Xiang Wu, "New Developments and Evaluations of the CALPUFF Model," March 14-16, 2012.) Despite all these advancements in modeling and modeling science, EPA conducted its modeling for its RH FIP Action in 2012 using the same (now outdated) CALPUFF version that PacifiCorp and Wyoming used 5 years ago, which has been shown to overestimate the visibility impacts and improvements by 300% to 400%.

Since 2012 EPA has taken an additional year to reconsider its initial FIP proposal. Disappointingly, EPA's RH FIP Action only considered using the outdated CALPUFF models rather than taking the opportunity to update the models to those that would represent the application of the best science available.

2. *EPA used a different background ammonia number for modeling than it requires of the states, and ignored current science on background ammonia.*

Regional haze modeling – and the resulting predicted visibility improvement – is greatly influenced by the background ammonia number used in the model. (*See* Exhibits 6 and 8.) EPA improperly used a constant 2 ppb background ammonia number for the Wyoming BART modeling. EPA has not provided any scientific proof showing the constant 2 ppb ammonia number is appropriate for Wyoming. The 2 ppb ammonia value overestimates visibility improvement, contrary to the approach used by Wyoming Land Use, IWAQM Guidance, WRAP protocols, and elsewhere. (*See* Attachments 7, 8 and 10.)

WRAP recommended the use of 1 ppb of ammonia year round for states in the region to account for seasonal variability. EPA has required states to use 1 ppb of background ammonia when conducting regional haze modeling. 76 Fed. Reg. at 52,434 (New Mexico criticized for not using 1 ppb background ammonia). While PacifiCorp disagrees with this view, at a minimum EPA should follow its own guidelines and use 1 ppb of background ammonia when conducting CALPUFF unit-specific modeling.

However, the "best" science requires the use of "variable ammonia" background numbers. IWAQM recommends 0.5 ppb for forest, 1ppb for dry/arid lands and 10ppb of ammonia for agriculture/grassland. Given its geographic location and elevation levels, Wyoming undergoes seasonal swings of dry-hot summers and snow covered ground in the winter. Therefore, the use of a single ammonia concentration for the entire year in a state where the land use and land cover changes significantly between seasons results in overestimation of visibility improvements. (*See e.g.,* Attachment 11, July 2, 2010 letter and attachment from Tri-State Generation to Colorado Air Pollution Control Division, discussing Mt. Zirkel area.) This is particularly true in winter when agricultural activity is minimal and meteorological conditions make visibility calculations particularly sensitive to ambient ammonia concentrations. (*See* Attachments 7 and 11.) EPA has approved the use of variable gaseous ammonia concentrations before, including the Addendum to Modeling Protocol for the Proposed Desert Rock Generating Station (ENSR, 2006),[44] and should have used them when conducting the CALPUFF modeling for Wyoming.

Sensitivity tests on ambient ammonia concentrations were performed by the Colorado Department of Public Health and Environment for an area in northwest Colorado. (*See* Attachment 8 and 11.) The analysis demonstrated that visibility calculations performed at Mount Zirkel Wilderness Area in northwest Colorado had limited impact when ambient ammonia concentrations were reduced from 100 to 1 ppb, but there was a significant reduction in visibility impacts when concentrations were further reduced to 0.1 ppb. Given the evidence presented above, the use of the monthly varying ammonia would provide accurate estimates of visibility impacts from the PacifiCorp RH Units. EPA's failure to use the "best science," variable background ammonia in its modeling, is arbitrary and capricious.

[44] The modeling files containing the ammonia concentrations for the Desert Rock Generating Station can be found on the EPA website under the administrative record for the project (http://www.epa.gov/region9/air/permit/desert- rock/administrative.html).

Moreover, EPA Region 8 has admitted the validity of using "variable ammonia" for CALPUFF modeling. In its federal implementation plan for Montana, EPA used "variable ammonia" in its modeling. 77 Fed. Reg. at 57,867. ("As a result, we did not assume a constant level of ammonia as asserted by the commenter, and we did represent seasonal variability in ammonia concentrations. Additionally, EPA used the POSTUTIL program " with the Ammonia Limiting Method (ALM) to post-process the CALPUFF output to correct the assumption of constant ammonia availability in the model.").

3. *EPA used the wrong CALPOST Method.*

EPA made another modeling error in Wyoming when it used CALPOST[45] version 5 with Method 6. Federal Land Manager recommendations in 2000 (FLAG) recommended the use of Method 6 to determine visibility impacts from BART eligible sources. However, for any recent PSD application and BART modeling since 2010, EPA has requested that Method 8 be used for determining impacts on visibility at nearby class I areas.

The previously preferred Method 6 simply computes background light extinction using monthly average relative humidity adjustment factors particular to each Class I area applied to background and modeled sulfate and nitrate. Six years after the development of Method 6 in 1999, EPA released enhancements to the background light extinction equations, which use the IMPROVE variable extinction efficiency formulation. These enhancements take into account the fact that sulfates, nitrates and organics and other types of particles have different light extinction coefficients. Also, the background concentrations at each Class I area have been updated by EPA to reflect natural background visibility condition estimates for each Class I area for each type of particle: ammonium sulfate, ammonium nitrate, organic matter, elemental carbon, soil, crustal material, sea salt and air molecules. Additionally, relative humidity adjustment factors have been tailored separately for: small particles, large particles, and to account for sea salt background concentrations. (*See* Attachment 7.)

These new enhancements to the calculation method, called Method 8, greatly improve the accuracy of the estimated visibility impact. Method 8 was added to CALPOST in 2008 and was adopted as the preferred option for determining impacts on visibility by the Federal Land Managers Air Quality Related Values Work Group (FLAG) guidance document in 2010 (FLAG 2010). The applicable background concentrations and relative humidity adjustment factors using Method 8 for each Class I area are identified in the FLAG 2010 manual. (*See* Attachment 7.)

Despite this update to Method 8 in 2008 and the stated preference by the FLMs in 2010 to use Method 8, EPA conducted the Wyoming BART modeling in 2012 using the long outdated and scientifically inferior Method 6. EPA's use of Method 6, and not Method 8, is arbitrary and capricious. EPA should have used Method 8, the "best" modeling science.

[45] CALPOST is a post-processing program with options for the computation of time-averaged concentrations and deposition fluxes predicted by the CALPUFF model.

In EPA's RH FIP Action, EPA made several errors concerning modeling, including 1) given the general inaccuracy in CALPUFF unit-specific modeling, not allowing Wyoming the deference accorded it under the CAA; 2) relying upon an outdated CALPUFF method of visibility modeling, contrary to EPA precedent; 3) violating the applicable modeling guidance, Appendix W, by not using the "best" science; 4) violating the Data Quality Act by not using the "best" science; and 5) failing to recognize the gross overestimations and internal inconsistencies in EPA's modeling approach.

States are not only given great discretion in relation to modeling, they are encouraged by EPA guidance to apply the most realistic models. Contrary to its own guidance, EPA failed to do so. Appendix W, EPA's modeling guidance, demands that the "best" model should always be used. EPA failed to use the "best" model in Wyoming. Therefore, EPA failed to follow Appendix W's requirements. App. W.1.0.e ("(I)n all cases, the model applied to a given situation should be the one that provides the most accurate representation of atmospheric transport, dispersion, and chemical transformations in the area of interest."); App. W.1.0.d ("The model that most accurately estimates concentrations in the area of interest is always sought.") (emphasis added). EPA's outdated modeling approach fails to meet the requirements of Appendix W.

iv) EPA's use of the maximum dV improvement that occurs during the 2001-2003 period does not provide the degree of visibility improvement which may reasonably be anticipated from the use of BART.

In its BART determinations, EPA relied on the maximum annual visibility impacts and improvements occurring during any given year of the 2001-2003 time period over which the models were run. Standard practice has been, and continues to be, to average the results over the three year period. (*See* e.g., 76 Fed. Reg. 16,168, 16,182 (approving the averaging of three different years in Oklahoma)). EPA's use of the maximum value is no more supportable than if a state or regulated source used the minimum annual value.

Tables 15-25 below demonstrate the differences in the modeled visibility improvements when the standard method of using three-year averages is used rather than EPA's method of using the highest impacted year[46].

[46] Although PacifiCorp disagrees with the results of EPA's modeling, data for these tables come from EPA's spreadsheet "EPA-R08-2012-0026-0089 Feb 11, 2013 modeling results.xlsx" to demonstrate how using the average values vs. the maximum values should be considered in EPA's BART determinations.

Table 15
Dave Johnston 1

EPA Modeled Delta dV Improvements from EPA's Baseline, Wind Cave NP Based on 98th Percentile Results						
	2001	2002	2003	3-Year Average	EPA Value	Difference between EPA and Average
LNB/OFA	0.204	0.110	0.308	0.21	0.31	0.10
SNCR	0.238	0.138	0.352	0.24	0.35	0.11
SCR	0.299	0.193	0.439	0.31	0.44	0.13

Table 16
Dave Johnston 2

EPA Modeled Delta dV Improvements from EPA's Baseline, Wind Cave NP Based on 98th Percentile Results						
	2001	2002	2003	3-Year Average	EPA Value	Difference between EPA and Average
LNB/OFA	0.203	0.112	0.288	0.20	0.29	0.09
SNCR	0.228	0.139	0.333	0.23	0.33	0.10
SCR	0.274	0.192	0.418	0.29	0.42	0.12

Table 17
Dave Johnston 3

EPA Modeled Delta dV Improvements from EPA's Baseline, Wind Cave NP Based on 98th Percentile Results						
	2001	2002	2003	3-Year Average	EPA Value	Difference between EPA and Average
LNB/OFA	0.500	0.395	0.639	0.51	0.64	0.13
SNCR	0.594	0.473	0.758	0.61	0.76	0.15
SCR	0.791	0.613	1.004	0.80	1.00	0.20
Improvement going from LNB to SCR	0.291	0.218	0.365	0.29	0.37	0.07

Table 18
Dave Johnston 4

EPA Modeled Delta dV Improvements from EPA's Baseline, Wind Cave NP Based on 98th Percentile Results						
	2001	2002	2003	3-Year Average	EPA Value	Difference between EPA and Average
LNB/OFA	0.695	0.546	0.838	0.69	0.84	0.15
SNCR	0.696	0.614	0.946	0.75	0.95	0.19
SCR	0.815	0.737	1.213	0.92	1.21	0.29
Improvement going from LNB to SNCR	0.001	0.068	0.108	0.06	0.11	0.05

Table 19
Jim Bridger 1

EPA Modeled Delta dV Improvements from EPA's Baseline, Mt Zirkel Based on 98th Percentile Results						
	2001	2002	2003	3-Year Average	EPA Value	Difference between EPA and Average
LNB/OFA	0.449	0.592	0.554	0.53	0.59	0.06
SNCR	0.525	0.694	0.651	0.62	0.69	0.07
SCR	0.724	0.964	0.873	0.85	0.96	0.11
Improvement going from LNB to SCR	0.275	0.372	0.319	0.32	0.37	0.05

Table 20
Jim Bridger 2

EPA Modeled Delta dV Improvements from EPA's Baseline, Mt Zirkel Based on 98th Percentile Results						
	2001	2002	2003	3-Year Average	EPA Value	Difference between EPA and Average
LNB/OFA	0.412	0.549	0.508	0.49	0.55	0.06
SNCR	0.495	0.654	0.612	0.59	0.65	0.07
SCR	0.714	0.951	0.861	0.84	0.95	0.11
Improvement going from LNB to SCR	0.302	0.402	0.353	0.35	0.40	0.05

Table 21
Jim Bridger 3

EPA Modeled Delta dV Improvements from EPA's Baseline, Mt Zirkel Based on 98th Percentile Results						
	2001	2002	2003	3-Year Average	EPA Value	Difference between EPA and Average
LNB/OFA	0.375	0.501	0.463	0.45	0.50	0.05
SNCR	0.460	0.608	0.569	0.55	0.61	0.06
SCR	0.688	0.918	0.829	0.81	0.92	0.11
Improvement going from LNB to SCR	0.313	0.417	0.366	0.37	0.42	0.05

Table 22
Jim Bridger 4

EPA Modeled Delta dV Improvements from EPA's Baseline, Mt Zirkel Based on 98th Percentile Results						
	2001	2002	2003	3-Year Average	EPA Value	Difference between EPA and Average
LNB/OFA	0.491	0.629	0.551	0.56	0.63	0.07
SNCR	0.583	0.753	0.658	0.66	0.75	0.09
SCR	0.834	1.011	0.939	0.93	1.01	0.08
Improvement going from LNB to SCR	0.343	0.382	0.388	0.37	0.39	0.02

Table 23
Naughton 1

EPA Modeled Delta dV Improvements from EPA's Baseline, Bridger Wilderness Based on 98th Percentile Results						
	2001	2002	2003	3-Year Average	EPA Value	Difference between EPA and Average
LNB/OFA	0.835	0.675	0.734	0.75	0.84	0.09
SNCR	0.985	0.793	0.866	0.88	0.99	0.10
SCR	1.230	0.982	1.079	1.10	1.23	0.13
Improvement going from LNB to SCR	0.395	0.307	0.345	0.35	0.40	0.05

Table 24
Naughton 2

EPA Modeled Delta dV Improvements from EPA's Baseline, Bridger Wilderness Based on 98th Percentile Results						
	2001	2002	2003	3-Year Average	EPA Value	Difference between EPA and Average
Baseline	--	--	--	--	--	--
LNB/OFA	0.969	0.788	0.903	0.89	0.97	0.08
SNCR	1.148	0.922	1.063	1.04	1.15	0.10
SCR	1.421	1.134	1.316	1.29	1.42	0.13
Improvement going from LNB to SCR	0.452	0.346	0.413	0.40	0.45	0.05

Table 25
Wyodak

EPA Modeled Delta dV Improvements from EPA's Baseline Wind Cave NP Based on 98th Percentile Results						
	2001	2002	2003	3-Year Average	EPA Value	Difference between EPA and Average
Baseline	--	--	--	--	--	--
LNB/OFA	0.192	0.207	0.242	0.21	0.24	0.03
SNCR	0.282	0.321	0.376	0.33	0.38	0.05
SCR	0.518	0.593	0.707	0.61	0.71	0.10
Improvement going from LNB to SNCR	0.090	0.114	0.134	0.11	0.13	0.02

From a visibility perspective these small differences are irrelevant. However, because EPA relies on very small modeled differences in visibility to justify the addition of hundreds of millions of dollars of BART controls these differences become very significant. EPA's use of the maximum annual improvement rather than the average value in its BART determinations results in the use of inflated visibility impacts and over-estimated improvements. For example, if EPA were to make no other change in interpreting the modeling results other than use the average dV improvement rather than the maximum annual value, the incremental visibility impact between installing LNB technology and SCR at Dave Johnston Unit 3 drops from 0.37 dV to 0.29 dV. SCR installation for this size of unit cannot be justified for a 0.37 dV improvement let alone a 0.29 dV improvement. Yet EPA chooses to rely on the inflated improvement values in an attempt to justify the installation of SCR on this unit. As a result, EPA's BART NO_X determinations are flawed and invalid. Similar conclusions can be reached for the other units that EPA addresses in its FIP.

v) EPA's use of the cumulative dV from several parks does not provide the degree of visibility improvement which may reasonably be anticipated from the use of BART.

In its disapproval of Wyoming's BART analyses, EPA uses an improper and illegal visibility analysis technique: the cumulative visibility analysis. 78 Fed. Reg. at 34,738. ("Although the cost-effectiveness and visibility improvement are within the range of other EPA RH FIP actions, we find that the *cumulative visibility improvement* of 1.16 deciviews for new LNBs with OFA plus SCR is low compared to *the cumulative visibility benefits* that will be achieved by requiring SCR at Dave Johnston Unit 3 (2.92 dv), Laramie River Unit 1 (2.12 dv), Laramie River Unit 2 (1.97 dv), Laramie River Unit 3 (2.29 dv), Naughton Unit 1 (3.54 dv), and Naughton Unit 2 (4.18 dv).") (emphasis added). Clearly, EPA considered "cumulative visibility improvement" when it rejected Wyoming's BART NO_X analyses and required SCR at Dave Johnston Unit 3 (78 Fed. Reg. at 34,778), Naughton Unit 1, and Naughton Unit 2. 78 Fed. Reg. at 34,782 ("In addition, the installation of SCR will also have substantial visibility benefits for other Class I areas, besides the most impacted area. The *cumulative visibility improvement* is 3.54 dv for Unit 1 and 4.18 dv for Unit 2.") EPA's use of the cumulative visibility analysis is incorrect for several reasons.

1. The EPA's cumulative visibility analysis is deceptive, and unreliable.

EPA fails to mention when presenting its cumulative visibility analyses that the modeled deciview improvements that are added together occur on different days, weeks, or even months. In spite of this, EPA adds together these disparate deciview improvements to arrive at a single deciview number as if that can somehow represent the true deciview improvements to be attained every day of the year at each of the Class I areas. *See e.g.* Tables 54 and 56, 78 Fed. Reg. at 34,782. This representation is totally false and deceptive.

For example, if modeling for a given control projected a visibility improvement at Area A of 0.1 dv on January 1st, at Area B of 0.2 dv on January 15th, at Area C of 0.2 dv on January 30th, at Area D of 0.2 dv on February 2nd, at Area E of 0.2 dv on February 8th, and at Area F of 0.1dv on February 16th, the "cumulative approach" would suggest a 1.0 dv improvement (the sum of all modeled improvements) could be attained at a Class I area. Because one deciview is considered the amount of visibility improvement perceptible to the human eye, the "cumulative approach" would suggest that the required technology would yield a perceptible visibility improvement. It is clear from this simple example, however, that the modeled control did not produce a perceptible visibility improvement at any of the Class I areas. In fact, based upon this example, the proposed control would not result in a perceptible difference anywhere. Likewise, adding the numbers in Tables 47, 54, and 56 Fed. Reg. at 34,778 and 34,782 of EPA's proposed RH FIP leads to the impression that a perceptible visibility improvement will occur, when in reality none of the modeled visibility improvements would be perceptible to the human eye.

2. *EPA's cumulative visibility analyses ignore the discretion given to States.*

The CAA provides that the States are to conduct the five-factor BART analysis of their stationary sources, which includes the determination of "the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology." 42 U.S.C. § 7491(g)(2). EPA has stated that because "each Class I area is unique, . . . *States should have flexibility to assess visibility improvements due to BART controls by one or more methods,* or by a combination of methods," and that "*States should have flexibility when evaluating the fifth statutory factor (degree of visibility improvement).*" 70 Fed. Reg. at 39,107. When discussing visibility improvement in the Preamble, EPA made it clear that States are to determine the "weight and significance" of each of the five BART factors. "*The State makes a BART determination based on the estimates available for each criterion, and as the CAA does not specify how the State should take these factors into account, the States are free to determine the weight and significance to be assigned to each factor.*" *Id.* at 39,123 (emphasis added); *see also* 77 Fed. Reg. 24,768, 24,774 (Apr. 25, 2012) ("States are free to determine the weight and significance to be assigned to each (BART) factor.").

Here, Wyoming reviewed and analyzed visibility modeling, and conducted an analysis of the "visibility improvement" BART factor. EPA ignored Wyoming's discretion, and is attempting to substitute its visibility analysis, including the deceptive and incorrect cumulative visibility analysis, for Wyoming's visibility analysis.

3. *EPA's cumulative visibility analysis lacks support in the Regional Haze Rules.*

The BART rules provide no support for EPA's "summation of cumulative impacts" approach. Rather, the BART rules first make clear that the initial focus is expected to be on the "nearest Class I area" to the facility in question . 70 Fed. Reg. 39,104, 39,162 (Sept. 6, 2005) ("One important element of the (modeling) protocol is in establishing the receptors that will be used in the model. The receptors that you (i.e., the state) use should be located in the *nearest* Class I area with sufficient density to identify the likely visibility effects of the source." (emphasis added)). The rules then indicate that it is appropriate to take account of impacts at not only the nearest Class I area but also impacts at other nearby Class I areas, not for the purposing of *summing* impacts at all of those areas, but rather for the purpose of "determin (ing) whether effects at those (other) areas *may be greater than* at the *nearest* Class I area." *Id.* (emphases added). Critically, "(i)f the highest modeled effects are observed at the nearest Class I area, *you (*i.e.*, the state) may choose not to analyze the other Class I areas any further* as additional analyses might be unwarranted." *Id.* (emphasis added).

Admittedly, the BART rules do not *preclude* a state from taking into account, as part of a BART assessment for a given facility, visibility impacts projected to occur in two or more Class I areas that are attributable to that facility's emissions. However, nothing in the rules requires such an analysis, and as explained herein, such analyses are deceptive when used in a cumulative fashion. Wyoming's visibility analyses should be upheld because Wyoming took "into consideration . . . the degree of improvement in visibility which may reasonably be anticipated to result from the use of" BART. 40 C.F.R. § 51.308(e)(1)(ii)(A). Regardless of EPA's empty statements to the contrary, EPA did not have the authority to disapprove Wyoming's visibility improvement analyses on the grounds that EPA prefers a different approach than the lawful and permissible approach taken by Wyoming. *See Train v. Natural Res. Def. Council, Inc.*, 421 U.S. 60, 79 (1975).

4. *The "Cumulative Approach" distorts the visibility improvement analysis and is not a useful tool*

Although EPA may prefer the use of the cumulative visibility analysis, there is no required, compelling, legal or even sound public policy reason for adopting such a methodology here. The metric by which visibility improvement is determined for purposes of assessing BART for a particular facility must reflect actual human perception of visibility. The terms "visibility impairment" and "impairment of visibility" are both defined by conditions (reduction in visual range and atmospheric discoloration) that are perceptible to the human eye. 42 U.S.C. §7491(g)(6).

The "cumulative approach" has no tie to human perception because it adds together modeled improvement that different people may (or may not) see at different places and different times, and then assumes the aggregate improvements can be perceived by all people at all places and at all times. In the end, the "cumulative approach" serves only to distort a BART analysis so it appears to justify expensive emission controls that do not improve visibility in any one Class I area to a degree that justifies the cost. It is unreasonable to assume that an individual can perceive visibility impacts in more than one Class I area simultaneously, or even within relatively short periods of time. Further, the "cumulative approach" incorrectly and arbitrarily multiplies the benefit that might be associated with emission limitations at a single source.

Similarly, the arbitrary nature of this approach is illustrated by the fact that it would equate an accumulation of vanishingly small – indeed, merely theoretical – visibility "benefits" in several different areas with a much larger and plainly perceptible improvement in a single area. It cannot reasonably be asserted that visibility improvements that are imperceptible in each of several Class I areas can somehow be the equivalent of – or even deemed more significant than – a much larger and humanly perceptible improvement in a single area.

The fallacy of the "cumulative approach" also can be illustrated by an analogy. If a weight loss drug company were to advertise that "A study shows 20 lbs. weight loss achievable in 30 days" by using its expensive drugs, it would be considered misleading if the study was "cumulative," i.e. 100 people each lost 0.2 lbs. on the drug over 30 days. However, if the weight loss drug truthfully advertised "A study shows 100 people each lost 0.2 lb in 30 days," while truthful, it is doubtful that the product would be sold to people expecting to lose 20 pounds. Likewise, EPA adding up the small, modeled visibility improvements at a number of Class I areas does not magically result in improved visibility as perceived by the human eye in all such Class I areas or in any one Class I area.

A modeled visibility benefit that no one can perceive and that is subject to arbitrary manipulation is not a real, quantifiable benefit. It is a fabricated value with no clear tie to the public interest that the CAA seeks to protect: human perception of visibility impairment in Class I areas.

vi) EPA ignores the days per year of improvement identified in the models they use, leaving the impression that the modeled visibility improvement occurs continuously.

In addition to improperly considering and weighing the magnitude of the modeled visibility impacts, EPA has improperly failed to account for the very few number of days of visibility impacts or the seasonal timing of when those few impacts occur. Table 26 below, created for Dave Johnston Unit 3, identifies the number of days per year that have been modeled to impact the identified Class I area by 0.5 deciviews or more. Although EPA does not specifically identify the number of days that were modeled to be above 0.5 dV in its FIP, the days were obtained by re-running EPA's models and model inputs.

Table 26

Dave Johnston Unit 3 Wind Cave NP – Days Modeled with Impacts <0.5 dV				
Model Year	2001	2002	2003	AVG
2001 – 2003 Baseline	22	21	24	22
LNB/OFA – Current Baseline	9	5	10	8
SNCR	3	4	10	6
SCR	1	0	2	1
Days Above 0.5dV That Are Eliminated by adding the Identified Controls				
SNCR	6	1	0	2
SCR	8	5	8	7

As can be seen from the results in the table, prior to the installation of LNB/OFA, EPA's models indicated that, on average, there would be 22 days per year where the impacts in Wind Cave National Park would be greater than 0.5 dV. The number of days impacting the park by more than 0.5 dV drops to eight days per year following the installation of the LNB/OFA, which is the current emissions configuration. EPA's proposed RH FIP Action, which requires the installation of SCR, will reduce the number of days that impact the park by < 0.5 dV from eight days to one day, just a seven day per year decrease.

Tables 27–30 provide similar information for the other units identified in EPA's RH FIP

Table 27

Dave Johnston Unit 4 Wind Cave NP – Days Modeled with Impacts <0.5 dV				
Model Year	2001	2002	2003	AVG
2001 – 2003 Baseline	31	24	26	27
LNB/OFA – Current Baseline	7	9	12	9
SNCR	7	7	9	8
SCR	3	3	7	4
Days Above 0.5dV That Are Eliminated by adding the Identified Controls				
SNCR	0	2	3	1
SCR	4	6	5	5

Table 28

Naughton Unit 1 Jim Bridger Wilderness Area– Days Modeled with Impacts <0.5 dV				
Model Year	2001	2002	2003	AVG
2001 – 2003 Baseline	42	26	33	34
LNB/OFA – Current Baseline	17	11	13	14
SNCR	10	8	10	9
SCR	5	3	4	4
Days Above 0.5dV That Are Eliminated by adding the Identified Controls				
SNCR	7	3	3	5
SCR	12	8	9	10

Table 29

Naughton Unit 2 Jim Bridger Wilderness Area – Days Modeled with Impacts <0.5 dV				
Model Year	2001	2002	2003	AVG
2001 – 2003 Baseline	45	34	43	41
LNB/OFA – Current Baseline	22	16	15	18
SNCR	16	11	13	13
SCR	10	6	9	8
Days Above 0.5dV That Are Eliminated by adding the Identified Controls				
SNCR	6	5	2	5
SCR	12	10	6	10

Table 30

Wyodak* Wind Cave NP – Days Modeled with Impacts <0.5 dV				
Model Year	2001	2002	2003	AVG
2001 – 2003 Baseline	41	38	37	39
LNB/OFA – Current Baseline	11	17	19	16
SNCR	11	14	11	12
SCR	0	3	8	4
Days Above 0.5dV That Are Eliminated by adding the Identified Controls				
SNCR	0	3	8	4
SCR	11	14	11	12
*Additional modeling for Wyodak has not been completed using EPA's revised model inputs. Data in this table on the modeling results included in Wyodak's Wyoming BART Application Analysis, AP-6043 page 32				

The LNB/OFA controls already installed on each BART-eligible unit in Wyoming ensure the 20% best days continue to be protected during this planning period. EPA's proposed FIP incurs millions of dollars of additional costs without moving the state any closer to being able to meet its reasonable progress goals.

vii) EPA has improperly required additional visibility controls with little to no associated visibility improvement.

A review of the unit-specific CALPUFF modeling results developed for the Mount Zirkel Wilderness Area provides a vivid example of the over-estimation of the visibility improvement that EPA is relying on to justify the installation of hundreds of millions of dollars in additional SCR controls. The following table summarizes the unit-specific CALPUFF visibility improvements that have been modeled for eight of PacifiCorp's coal-fired units in Colorado and Wyoming. The table identifies EPA's modeled ΔdV improvements associated with reducing the NO_X emissions from each unit's EPA NO_X baseline to the NO_X emissions associated with the installation of SCR:

Table 31

EPA Modeled Improvements at Mount Zirkel for Eight of PacifiCorp Owned Facilities	
Facility	Modeled ΔdV Improvement
Jim Bridger 1	0.80
Jim Bridger 2	0.80
Jim Bridger 3	0.80
Jim Bridger 4	0.82
Craig 1	1.01
Craig 2	0.98
Hayden 1	1.12
Hayden 2	0.85
Total Modeled Visibility Improvement	7.18

The unit specific CALPUFF modeling would indicate that adding SCR to these units would improve visibility in Mount Zirkel by over seven deciviews.

However, the monitored data at Mount Zirkel tells a completely different story. Table 32[47] below is a summary of the visibility impairment actually measured at the Mount Zirkel Wilderness area from 2001-2003. This is the same time period used in the CALPUFF models to develop the deciview impacts for each Wyoming BART-eligible unit and to project the visibility improvements associated with the addition of control devices. The ammonium nitrates values have been highlighted since the contribution associated with nitrates is what is of interest in this evaluation.

[47] The table compares the monitored light extinction with deciviews so that the monitored impacts can be properly compared to the modeled results. In order to develop the deciview impact of each parameter, the light extinction associated with each parameter was removed one parameter at a time and the resulting dV impact calculated. The difference between the total impact and this value provides the dV improvement that is associated with completely removing the specified parameter. The relationship between light extinction and deciviews is: Deciview (dV) = 10 x ln (bext(Mm-1)/10).

Table 32

Mount Zirkel Wilderness Area - 2001-2003 Reconstructed Extinction Values MOZI1 Monitoring Data - 20% Worst Visibility Days[48]			
Parameter	bext Mm^{-1}	% Of Total bext	Deciview Improvement if Parameter is Completely Removed
Ammonium Nitrate	**2.3**	**8.9%**	**0.94**
Ammonium Sulfate	5.5	21.4%	2.41
Course Material	3.6	14.0%	1.51
Elemental Carbon	2.0	7.8%	0.81
Organic Material	11.3	43.9%	5.79
Sea Salt	0.0	0.1%	0.01
Soil	1.0	3.9%	0.40
Total Impact	25.7	100.0%	9.45

Looking at the 3-year average results, and assuming that the nitrates associated with the emissions from all sources (not just the BART-eligible EGUs) are completely eliminated, only a 0.94 deciview improvement would be expected. EPA attempts to justify over a billion dollars in controls at eight PacifiCorp Units by assuming more than 7 deciviews of improvement could be obtained from these eight units when the actual monitored data indicates that only a 0.94 dV improvement would be possible if all nitrate was removed from all sources. In essence, EPA's RH FIP Action fails to recognize that, given the monitored nitrate impacts, the modeled visibility impacts are obviously grossly exaggerated. For this reason alone, EPA should withdraw its RH FIP and approve the Wyoming RH SIP in total.

Moreover, in its RH FIP Action, EPA ignores Wyoming's discretion to consider, and account for in its BART determinations, the admitted "overestimation" of CALPUFF results. As EPA itself has stated, Wyoming should be free to make its own judgment about which modeling approaches are valid and appropriate.

Determining "visibility improvement" for regional haze program purposes is challenging, and extreme caution must be exercised when conducting visibility-related modeling and interpreting the modeling results. Modeling mistakes and misinterpretation of the data can lead to poor decision-making with expensive consequences.

The unit-specific CALPUFF modeled visibility impacts on the Grand Canyon from the former Mojave power plant are another example of how CALPUFF can incorrectly attribute visibility impacts. For years, computerized models (the same CALPUFF model used in Wyoming) showed that closing the Mojave power plant would improve visibility by 5% or more. (*See* Attachment 12, Terhorst, J., Berkman, M., "Effect of Coal-Fired

[48] http://vista.cira.colostate.edu/dev/web/AnnualSummaryde v/Composition.aspx

Power Generation on Visibility in a Nearby National Park," Atmospheric Environment (2010), page 15.) The CALPUFF unit-specific models, however, were wrong. Mojave was closed in 2005, but scientists "found virtually no evidence that the (Mojave) closure improved visibility in the Grand Canyon; or, equivalently, that the plant's operation degraded it." *Id.* at 14. These same scientists believed that the Mojave study raises "questions about the reliability of CALPUFF." *Id.* at 15. Likewise, EPA should question its use of CALPUFF unit-specific modeling results in Wyoming.

viii) EPA is not affording Wyoming's BART decisions the proper deference when it comes to the modeling and applying the modeling results.

The CAA provides that the states are to conduct the five-factor BART analysis of their stationary sources, which includes the determination of "the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology." 42 U.S.C. § 7491(g)(2). EPA explained that "we must permit States to take into account the degree of improvement in visibility that would result from imposition of BART on each individual source when deciding on particular controls." 70 Fed. Reg. 39,107, 39,129. Additionally, EPA has stated that because "each Class I area is unique, . . . <u>States should have flexibility to assess visibility improvements due to BART controls by one or more methods, or by a combination of methods</u>," and that "<u>States should have flexibility when evaluating the fifth statutory factor</u>." 70 Fed. Reg. at 39,107 (emphasis added). Wyoming exercised that discretion here, but, once again, EPA failed to grant it the proper deference.

1. *EPA failed to allow Wyoming to account for CALPUFF's overestimation of NO_X impacts.*

EPA recognized that states are accorded significant "modeling" discretion because CALPUFF chronically overestimates modeled visibility improvements. The Preamble recognizes that states can make judgments regarding the use of modeling results due to the very real problems with CALPUFF.

> At a minimum, CALPUFF can be used to estimate the relative impacts of BART-eligible sources. We are confident that CALPUFF distinguishes, comparatively, the relative contributions from sources such that the differences in source configurations, sizes, emission rates, and visibility impacts are well-reflected in the model results. <u>States can make judgments concerning the conservativeness or overestimation, if any, of the results.</u>
>
> . . .
>
> We understand the concerns of commenters that the chemistry modules of the CALPUFF model are less advanced than some of the more recent atmospheric chemistry simulations. To date, no other modeling applications with updated chemistry have been approved by EPA to estimate single source pollutant concentrations from long range transport. In its next review of the Guideline on Air Quality Models, EPA will evaluate these and other newer approaches and

determine whether they are sufficiently documented, technically valid, and reliable to approve for general use. In the meantime, as the Guideline makes clear, States are free to make their own judgments about which of these or other alternative approaches are valid and appropriate for their intended applications.

70 Fed. Reg. at 39123 (emphasis added). As the Mojave power plant study illustrates, there are serious questions about CALPUFF's credibility. (*See* Exhibit 4.) The Mojave study suggests that, at a minimum, visibility improvements modeled by CALPUFF may be greatly overstated. As EPA stated in the Arizona RH FIP, the "Terhorst & Berkman study cited by the commenter is worthy of consideration as the Regional Haze program evolves. . ." 78 Fed. Reg. at 72,534.

EPA's own studies document that CALPUFF overstates results. In a May 2012 study of CALPUFF, an EPA sponsored study found "the current and past CALPUFF model performance evaluations were consistent with CALPUFF tending to overestimate the plume maximum concentrations and underestimate plume horizontal dispersion." Documentation of the Evaluation of CALPUFF and Other Long Range Transport Models Using Tracer Field Experiment Data, May 2012, EPA-454/R-12-003, page 29. The study also recognized that modeling results were widely variable, depending on the options used, and that such variability is "not a desirable attribute for regulatory modeling." *Id. at* 11; *see also* page 18 (."By varying CALMET inputs and options through the range of plausibility, CALPUFF can produce a wide range of concentrations estimates."). Therefore, EPA's own recent studies suggest CALPUFF overestimates results and, therefore, its results should not be accorded scientific precision. Problems with CALPUFF unit-specific modeling reliability in Wyoming, and its tendency to grossly overestimate results, are discussed in the succeeding section below.

ix) EPA's modeling was inadequate and reliance on the modeling violates The Data Quality Act.

EPA's modeling for its RH FIP Action was inadequate for all the reasons stated above. Therefore, EPA's RH FIP Action violates the Information Quality Act[49] and the implementing guidelines issued, respectively, by the U.S. Office of Management and Budget (OMB)[50] and the EPA which require information disseminated by EPA to be accurate, complete, reliable and unbiased.[51] The Act and EPA Information Quality Guidelines place a heightened standard on "influential" information,[52] including

[49] Section 515(a) of the Treasury and General Government Appropriations Act for Fiscal Year 2001, P.L. 106-554; 44 U.S.C. §3516

[50] OMB Guidelines for Ensuring and Maximizing the Quality, Objectivity, Utility, and Integrity of Information Disseminated by Federal Agencies (hereinafter "OMB Guidelines"), 67 Fed. Reg. 8,452 (Feb. 22, 2002).

[51] OMB Guidelines 8,453.

[52] EPA Guidelines define "influential," when used in the phrase "influential scientific, financial, or statistical information," as information that "will have or does have a clear

scientific information regarding health, safety or environmental risk assessments. EPA's inaccurate and incomplete visibility modeling is by definition "influential," because EPA could "reasonably determine that dissemination of the information will have or does have a clear and substantial impact on important public policies or important private sector decisions," such as the BART NO_X determinations in EPA's RH FIP. OMB Guidelines at 8455. Therefore, this "influential" information must be based on best available science and data and supporting studies must be conducted in accordance with sound objective scientific practices and methods. EPA Information Quality Guidelines at 22. As explained above, EPA did not use the "best available science and data" when conducting its modeling in Wyoming.

EPA's Guidelines implementing the Information Quality Act expressly contemplate the correction of information disseminated by EPA that falls short of the "basic standard of quality, including objectivity, utility, and integrity," established by either EPA's own Guidelines or those issued by OMB. PacifiCorp herein seeks correction to a number of errors and omissions in EPA's RH FIP Action with regard to CALPUFF modeling PacifiCorp requests that EPA withdraw its RH FIP until these issues are resolved. [53]

x) EPA's Modeling Approaches are Inconsistent

EPA rejected Oklahoma's visibility analyses which "relied upon pollutant specific modeling to evaluate the benefits from the use of available SO_2 emission controls." 76 Fed. Reg. 81,728, 81,740. Rather, EPA modeled in Oklahoma "all visibility impairing pollutants to fully assess the visibility improvement anticipated from the use of controls." *Id.* EPA argued this modeling took into account "the complexity of atmospheric chemistry and chemical transformation among pollutants." *Id.* In Wyoming, EPA noted that Wyoming provided "visibility improvement modeling results that combine(d) the visibility improvement from NO_X, PM and SO_2 control options" and that "EPA could not ascertain what the visibility improvement would be from an individual NO_X or PM control option." 77 Fed. Reg. at 33,031. EPA appears to take contrary positions in Oklahoma and Wyoming. EPA's inconsistent positions are arbitrary and capricious.

In EPA's RH FIP Action, the alleged "visibility improvements" for DJ 3 and 4, Naughton 1 and 2, and Wyodak do not justify "overruling" the State's discretionary BART NO_X determinations. EPA found that SCR provided only a 0.36 ΔdV incremental visibility improvement for DJ3, using EPA modeling, with an incremental cost of $7,163.00. 78 Fed. Reg. 34,777-78. EPA failed to justify in its proposed rule how a 0.36 ΔdV improvement, or approximately one-third that humanly detectible, justifies the tremendous cost of SCR. Likewise, EPA found that installing SNCR at DJ 4 results in an incremental 0.11 ΔdV improvement over Wyoming's BART determination at an

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and substantial impact (i.e., potential change or effect) on important public policies or private sector decisions." EPA Information Quality Guidelines at 19.

[53] EPA should treat PacifiCorp's public comments herein as a formal "Request for Correction" pursuant to the EPA Information Quality Guidelines at 32 because the EPA's Proposed RH FIP Proposal is open for Public Comment.

incremental cost of $4,655. 78 Fed. Reg. 34,781-82. The alleged incremental visibility benefit of installing SNCR at Wyodak is 0.12 ΔdV at an incremental cost of $3,725. 78 Fed. Reg. 34,784-85. EPA provides no justification for requiring such tremendous costs for such an inconsequential visibility improvement that likely falls within CALPUFF's margin of error. However, these alleged "visibility improvements" do not justify requiring SCR and SNCR for BART, particularly when the air quality model's ("CALPUFF'S) propensity to exaggerate visibility improvements is considered . (*See* Section 6.)

EPA has determined in other states that visibility improvements greater than those used to justify SNCR at Wyodak are too small or inconsequential to justify additional pollution controls. (*See* 77 Fed. Reg. 24,794 (0.27 dV improvement termed "small" and did not justify additional pollution controls in New York); 77 Fed. Reg. 11,879, 11,891 (0.043 to 0.16 ΔdV improvements considered "very small additional visibility improvements" that did not justify NO_X controls in Mississippi); 77 Fed. Reg. 18,052, 18,066 (agreeing with Colorado's determination that "low visibility improvement (under 0.2 ΔdV)" did not justify SCR for Comanche units)) Tellingly , the "low visibility improvements" that Colorado found at the Comanche units not to justify post-combustion NO_X controls -- as agreed to by EPA -- were 0.17 and 0.14 ΔdV. 77 Fed. Reg. at 18,066.

In Montana, where EPA issued a RH FIP directly, it found that a 0.18 ΔdV improvement to be a "low visibility improvement" that "did not justify proposing additional controls" for SO_2 on the source. 77 Fed. Reg. 23,988, 24,012. Here, EPA's actions requiring additional NO_X controls based on little-to-no additional visibility improvement are arbitrary and capricious, especially when EPA did not require additional NO_X controls in other states based on similar visibility improvements. This is particularly true in Montana where EPA had direct responsibility for the regional haze program.

Moreover, the modeled visibility improvements for the Jim Bridger units resulting from the requirement to install SCR (as BART under the EPA RH FIP Action and as part of the LTS under the Wyoming RH SIP) are too small to justify the overall expense of requiring these controls, as are the less than 0.5 ΔdV visibility improvements for Naughton Units 1 and 2 at an incremental cost of approximately $7,000. EPA has upheld state BART discretion in other instances of high incremental cost and low incremental visibility improvement. *See* 76 Fed. Reg. 80754, 80,757 (Kansas); Spending hundreds of millions of dollars for imperceptible visibility changes does not meet the intent, or purpose, of the regional haze program.

(7) "Combustion Controls" are BART, as Explained by EPA's Guidance and Applicable Regional Haze Rules.

A. NO_X BART Controls for The Subject Units are Combustion Controls.

EPA's RH FIP Action is improper because it requires post-combustion NO_X controls as BART, when EPA guidelines make clear that only combustion controls for NO_X are contemplated. (*See e.g.* 77 Fed. Reg. at 33,053.) EPA's Preamble and other guidance confirm that the combustion controls of LNBs and OFA (in some form) are "BART technology" for the BART Units. In the Preamble and the Regional Haze Rules, EPA stated that, except for cyclone boilers, the "types of current combustion control technology options assumed include low NO_X burners, over-fire air, and coal reburning." 70 Fed. Reg. 39,134; *see also* 39,144 ("For all other coal-fired units, our analysis assumed these units will install current combustion control technology.") (emphasis added). In fact, in the Technical Support Document used to develop the presumptive BART NO_X emissions limits, EPA explained that the "methodology EPA used in applying current combustion control technology to BART-eligible EGUs" included applying "a complete set of combustion controls. A complete set of combustion controls for most units includes a low NO_X burner and over-fire air." ("Technical Support Document, Methodology for Developing NO_X Presumptive Limits," EPA Clean Air Markets Division, pg. 1 (dated June 15, 2005) (emphasis added)).

EPA's Preamble and Appendix Y identify post-combustion controls for NO_X, such as SCR and SNCR, as "BART technology" for only "cyclone" units. EPA made it clear that for "other units, we are not establishing presumptive limits based on the installation of SCR." 70 Fed. Reg. 39,136 (emphasis added). Therefore, EPA's presumptive "BART technology" is LNBs and some type of OFA. EPA further elaborated in the Preamble on SCR costs, stating that although "States may in specific cases find that the use of SCR is appropriate, we have not determined that SCR is generally cost-effective for BART across unit types." *Id.* (emphasis added)*; see also* 40 C.F.R. Part 51, Appendix Y, Section IV.E.5. Because EPA improperly requires post-combustion controls in its RH FIP Action, EPA should withdraw this requirement and approve the Wyoming RH SIP. If EPA desires to impose post-combustion controls as BART NO_X, it must first amend Appendix Y through a proper rulemaking procedure.

B. Post Combustion Controls Are Not Cost Effective Or Required.

EPA's RH FIP Action also is improper because it assumes BART NO_X controls over $5,000 per ton are "cost effective." (*See e.g.,* 77 Fed. Reg. at 33,053.) Appendix Y, on the other hand, states that BART NO_X control costs per ton above $1,500 are not "cost effective." In the Preamble, EPA suggests that 75% of the EGUs would have BART NO_X removal costs between $100 and $1,000 per ton, and almost all of the remaining EGUs could install sufficient BART NO_X control technology for less than $1,500 per ton.[54] EPA also recognized in the Preamble that SCR was generally not cost effective for

[54] "The limits provided were chosen at levels that approximately 75 percent of the units could achieve with current combustion control technology. The costs of such controls in most cases range from just over $ 100 to $ 1000 per ton. Based on our analysis, however, we concluded that approximately 25 percent of the units could not meet these limits with current combustion control technology. However, our analysis indicates that all but a very few of these units could meet the presumptive limits using advanced combustion controls such as rotating over fire air ("ROFA"), which has already been demonstrated on

EGUs, except for EGUs with cyclone boilers (where the cost per ton was less than $1,500 per ton, with an average of $900 per ton). 70 Fed. Reg. at 39,135-36. Based upon EPA's Preamble, BART NO_X control technology that costs more than $1,500 per ton should not be considered "cost effective." Here, EPA found BART NO_X controls with a "cost effectiveness" number much more than $1,500 per ton to be "cost effective." 77 Fed. Reg. at 33,053. Therefore, EPA should withdraw its RH FIP Action.

(8) <u>EPA's RH FIP Action is Arbitrary Because it Employs a "Reasonable Progress" Test For DJ 1 & 2 that is not used for other Wyoming Sources or For Sources in other States</u>

Additional evidence of EPA's failure to give Wyoming the proper deference relates to DJ 1 & 2 and the reasonable progress factors. EPA acknowledged that, for a Reasonable Progress analysis, only four factors must be analyzed. (*See* 78 Fed. Reg. at 34,763.) Indeed, the Clean Air Act clearly requires only four factors be analyzed . 42 U.S.C. § 7491(g)(1).[55] EPA employed the four-factor Reasonable Progress analysis for the other two Wyoming Reasonable Progress sources: oil and gas sources and the Mountain Cement Company plant.[56] *Id.* at 34,763-4 and 34,765-6. EPA has approved other RH SIPs where the state employed this same four-factor analysis, including Nevada. (*See* 77 Fed. Reg. 36,044, 36,070; *see e.g.* 77 Fed Reg. 20,894, 20,934 ("As we have noted, our regulations require consideration of four factors in reasonable progress determinations; visibility improvement is not one of the specified factors.")) Also, EPA has approved other RH SIPs where the state is not meeting the Uniform Rate of Progress, but has determined that no Reasonable Progress controls are required for the initial planning period. (*See* 77 Fed. Reg. 30,248, 30,256-57; RH SIP Approval for Idaho).

Here, EPA admitted that Wyoming "provided four-factor analyses that evaluated the required factors" for DJ 1 & 2. 78 Fed. Reg. 34,785. However, EPA decided to do its own cost analyses and found it is "also appropriate to consider a fifth factor for these

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a variety of coal-fired units. Based on the data before us, the costs of such controls in most cases are less than $ 1500 per ton." 70 Fed. Reg. at 39,135.

[55] "[I]n determining reasonable progress there shall be taken into consideration the costs of compliance, the time necessary for compliance, and the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any existing source subject to such requirements." 42 U.S.C.§ 7491(g)(1).

[56] For both the oil and gas sources and the Mountain Cement Company plant, EPA disagreed with Wyoming's reasonable progress analysis and found "cost effective" NO_X controls could be employed, but EPA did not require those NO_X controls because the costs were "not so low that we are prepared to disapprove the State's conclusion in the reasonable progress context." *Id.* at 34,765 and at 34,766. EPA does not differentiate PacifiCorp's DJ Units 1 & 2 from the oil and gas sources or the Mountain Cement Company plant in any meaningful way that would suggest a different Reasonable Progress analysis should be applied. It is unclear why EPA required allegedly "cost effective" NO_X controls at Dave Johnston Unit 1 and 2, but not at the other two reasonable progress sources.

units . . .the degree of visibility improvement." *Id.* EPA justified its decision by citing to EPA guidance on states setting Reasonable Progress goals.

However, the referenced guidance (Appendix T, "Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program," June 2007) does not support EPA's position for several reasons:

- The guidance concedes it is "merely guidance and that States or the . . . (EPA) may elect to follow or deviate from this guidance, as appropriate." *Id.* at 1-1. (emphasis added). EPA cannot find Wyoming acted "unreasonably" when it chose not to apply discretionary guidance.

- The guidance identifies several factors that EPA did not include in its proposed RH FIP, such as the "control measures and associated emission reductions that are expected to result from compliance with existing rules." *Id.* at 2-3. EPA cannot criticize Wyoming for not following the guidance when EPA itself chose not to apply part of the same guidance in the EPA RH FIP Action.

- The guidance suggests that air quality models be used to estimate "the improvement in visibility that would result from the implementation of the control measures you have found to be reasonable and compare this to the uniform rate of progress." *Id.* Here, EPA has no "modeling results" demonstrating the alleged improvement in visibility from the suggested NO_x controls and the impact on the uniform rate of progress . 77 Fed. Reg. at 33,057.

- The States -- not EPA -- are to determine the "reasonableness" of Reasonable Progress Goals and are given flexibility to do so. Appendix T at 4-2 ("you [states] have considerable flexibility in how you take these factors into consideration.") .

- The guidance clearly indicates that a state must support its RPG "based on the statutory factors," which EPA admits Wyoming did. *Id.*

- Finally, the guidance explains that no additional "Reasonable Progress" controls may be needed for the first planning period. *Id.* at 4-1. ("Given the significant emissions reductions that we anticipate will result from BART, the CAIR, and the implementation of other programs, including the ozone and $PM_{2.5}$ NAAQS, for many States this will be an important step in determining your RPG, and it may be all that is necessary to achieve reasonable progress in the first planning period for some States.") (emphasis added). This is exactly the determination Wyoming made.[57]

Therefore, the referenced guidance supports Wyoming's Reasonable Progress analysis for Dave Johnston Units 1 & 2 and Wyoming's finding that significant emissions reductions from BART and other CAA programs are sufficient for Reasonable Progress.

Moreover, EPA rejected Wyoming's Reasonable Progress determinations for Dave Johnston Units 1 & 2, in part, because EPA stated the "RHR does not allow for commitments to potentially implement strategies at some later date that are identified under reasonable progress or for the State to take credit for such commitments." 78 Fed. Reg. at 34,787. However, this is exactly what EPA allowed for other Reasonable Progress sources, such as the cement plant and oil and gas sources, to do. EPA's approach to the various Reasonable Progress sources is inconsistent and arbitrary.

Finally, EPA's Reasonable Progress analysis for Dave Johnston Units 1 & 2 is improper because it interferes with Wyoming's deference given under the CAA and applicable Regional Haze regulations. EPA disagrees with Wyoming's balancing of the costs and visibility, stating that EPA found it "unreasonable" for the State to reject "inexpensive controls" when there was a predicted visibility improvement of approximately 0.30 deciviews. 78 Fed. Reg. at 34,788. However, States, not EPA, are given the discretion and authority to balance the four Reasonable Progress factors. Appendix T at 4-2 ("you [states] have considerable flexibility in how you take these factors into consideration.").

(9) EPA Failed to take into Account the Impact of EPA's other Regional Haze Actions on PacifiCorp.

In making any BART determinations on a large, multi-jurisdictional system such as PacifiCorp's, the regulating agency must consider the broad scope of the impacts of its decisions on customers and generating system reliability as a whole. Wyoming considered these factors in developing its RH SIP. "The Division believes that the size of PacifiCorp's fleet of coal-fired units presents unique challenges when reviewing costs, timing of installations, customer needs, and state regulatory commission requirements. Information has been supplied by PacifiCorp elaborating on additional factors to be considered in PacifiCorp's BART determination (*see* 'PacifiCorp's Emissions Reductions Plan' in Chapter 6 of the Wyoming TSD)." RH SIP, at page 102. Wyoming's consideration of these factors was appropriate.

[57] In fact, Wyoming's RH FIP finds that the WRAP modeling showed a "significant decrease in nitrate by 2018," which was largely attributable to "the numerous Federal and state "'on-the-books' requirements for mobile sources." RH SIP at page 62.

As EPA's Regional Haze guidance, Appendix Y, explains:

1. Even if the control technology is cost effective, there may be cases where the installation of controls would affect the viability of continued plant operations.

2. There may be unusual circumstances that justify taking into consideration the conditions of the plant and the economic effects of requiring the use of a given control technology. These effects would include effects on product prices. . . Where there are such unusual circumstances that are judged to affect plant operations, you may take into consideration the conditions of the plant and the economic effects of requiring the use of a control technology. Where these effects are judged to have a severe impact on plant operations you may consider them in the selection process. . .

Appendix Y. IV.E.3. (emphasis added).

In EPA's June 2012 proposed RH FIP, EPA requested public comment, including economic impact and system reliability information, regarding three "alternative" proposals for the Jim Bridger plant. (*See* 77 Fed. Reg. at 33053-54.) PacifiCorp submitted additional material regarding this request on July 12, 2012 (included herein as Attachment 13), including discussion of additional exposure to market power purchases, impacts on management of planned outages, enhanced risk associated with resource availability, planning for adequate generation and reasonable costs, and planning for grid reliability in light of unprecedented retrofit activity. Given the large number of BART Units owned by PacifiCorp in different states, including Arizona, Colorado, Utah and Wyoming, PacifiCorp believes "unusual circumstances" justify Wyoming and EPA considering the impact of EPA's BART decision-making in the Western United States on PacifiCorp and its customers. The same concerns expressed in its July 12, 2012, filing apply in EPA's RH FIP Action, where even more controls are being required.

In its RH FIP Action, EPA relied upon PacifiCorp's July 12, 2012, filing to conclude that, "based on the points made by PacifiCorp and noting the additional requirements in the proposed FIP for Wyoming, the finalized FIP for Arizona, and the possibility of additional requirements in a future FIP or SIP for Utah, EPA is proposing that the additional time to install controls under the State's LTS on Jim Bridger Unit 1 and Unit 2 is warranted under the affordability provisions in the BART Guidelines discussed above." *See,* 78 Fed. Reg. at 34756.

PacifiCorp supports EPA's proposed action to afford "considerable deference" to the Wyoming RH SIP with respect to what controls are reasonable and when they should be implemented at Jim Bridger Units 1 and 2—and that it would be unreasonable to require any further retrofits at this source within five years of EPA's final action. This is especially true given the extremely limited visibility improvement that would be achieved if SCRs were installed within the BART time period at Jim Bridger Units 1 and 2.

Further, PacifiCorp does not believe EPA, having reached the conclusion that it would be unreasonable to require further retrofits at Jim Bridger within five years, can reverse its decision simply by inviting comment on an alternative proposal without further consideration of the broader impacts of forcing more aggressive controls within a five year period.

While PacifiCorp agrees with EPA's proposed conclusions regarding the reasonableness and timing of installation of controls at Jim Bridger Units 1 and 2, EPA's focus on affordability impermissibly fails to consider the unusual circumstances and broader impacts of its action on PacifiCorp's other BART Units. EPA's selection of SCR controls at Naughton Units 1 and 2 and at Dave Johnson Unit 3 will affect the viability of continued unit operations. As discussed herein, installation of SCR controls at these three units, particularly given the cost of controls and their remaining useful life, create such "unusual circumstances" that justify taking into consideration the conditions of the plant and the economic effects of requiring the use of a given control technology.

EPA, in failing to consider the unusual circumstances it has created in proposing SCR and in failing to consider those actions in light of the timing and reasonableness of controls at Jim Bridger Units 1 and 2, has acted in a manner that is arbitrary and capricious in its overall assessment (or lack thereof) of the effects of its actions on PacifiCorp's generation fleet. EPA's increasingly stringent requirements on PacifiCorp's fleet are summarized in Table 33.

Table 33

Unit	Wyoming SIP	2012 FIP	2013 FIP
Naughton 1	LNB	LNB	SCR (within 5 years)
Naughton 2	LNB	LNB	SCR (within 5 years)
Naughton 3	SCR (12/31/14)	SCR (12/31/14)	SCR (12/31/14)
Jim Bridger 1	SCR (12/31/22)	SCR (within 5 years)	SCR (12/31/22)
Jim Bridger 2	SCR (12/31/21)	SCR (within 5 years)	SCR (12/31/21)
Jim Bridger 3	SCR (12/31/15)	SCR (12/31/15)	SCR (12/31/15)
Jim Bridger 4	SCR (12/31/16)	SCR (12/31/16)	SCR (12/31/16)
Dave Johnston 1	LNB	LNB	LNB (within 5 years)
Dave Johnston 2	LNB	LNB	LNB (within 5 years)
Dave Johnston 3	LNB	SNCR (within 5 years)	SCR (within 5 years)
Dave Johnston 4	LNB	LNB	SNCR (within 5 years)
Wyodak	LNB	SNCR (within 5 years)	SNCR (within 5 years)

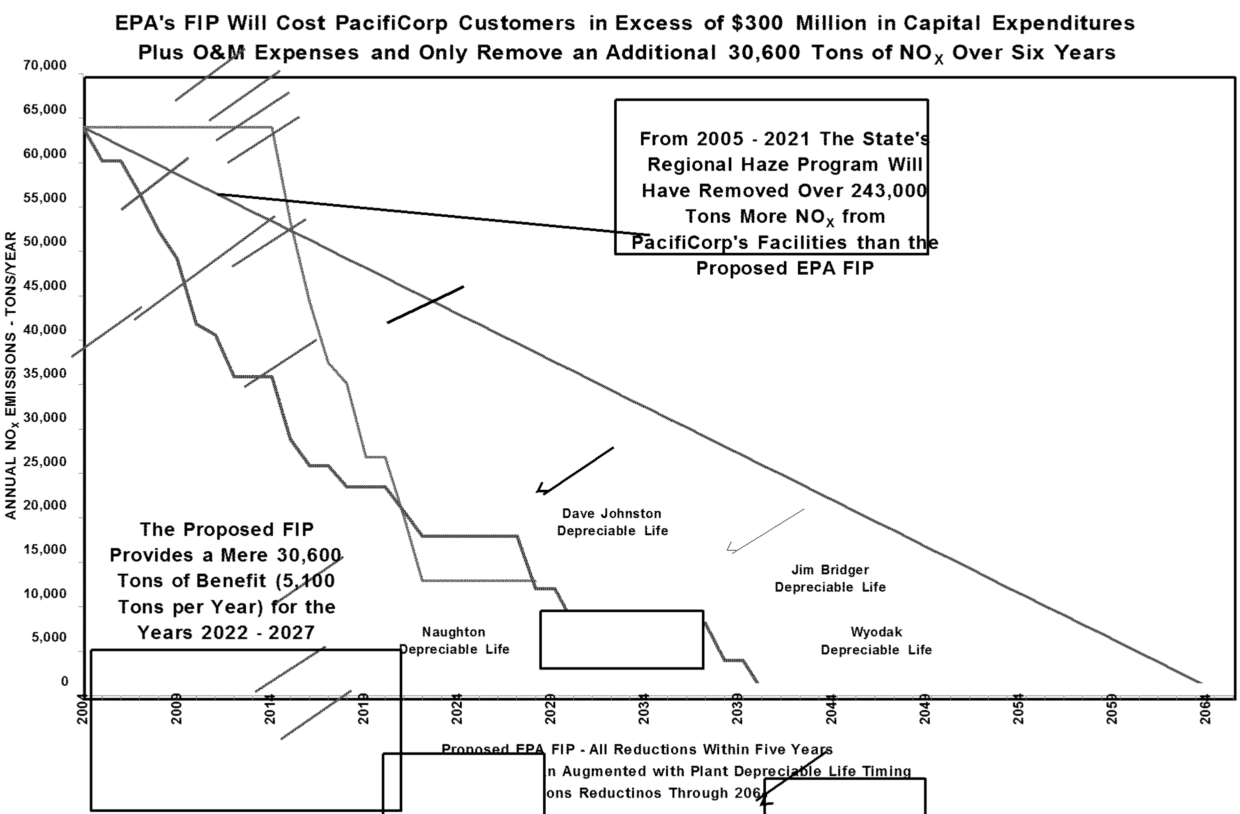
The eight SCR, two SNCR and low-NO_X burners required in EPA's proposed action must be considered in the context of the additional controls required at PacifiCorp's units in Arizona (Cholla Unit 4 with SCR required by 2017) and its share of units in Colorado (Hayden 1 with SCR in 2015, Hayden 2 with SCR in 2016, Craig Unit 1 with SNCR in 2017 and Craig Unit 2 with SCR required in 2016) and the potential for additional controls required at four of PacifiCorp's BART-eligible units in Utah within five years after final action. EPA's failure to consider the "unusual circumstances" contemplated under its Appendix Y Guidance when PacifiCorp ultimately has financial responsibility for achieving compliance with the Regional Haze requirements at 21 units, 16 of which may include the installation of SCR within a five to eight year period of time, is improper.

(10) EPA's Untimely Review of the Wyoming RH SIP was to the Extreme Detriment of PacifiCorp and its Customers.

Wyoming's regional haze program has been underway for several years. Under EPA's initial regional haze rules, BART controls were expected to be installed by the end of 2013. Wyoming appropriately and effectively developed and implemented a regional haze program that met the 2013 timeline. As required by the Wyoming RH SIP, and with the one exception of Naughton Unit 3 which has a deadline of 2014, PacifiCorp has fully implemented Wyoming's BART requirements for its Wyoming BART Units. As a result, in 2013 alone, there will be 76,000 fewer tons of visibility impairing pollutants emitted by PacifiCorp BART Units than was emitted in 2004.

Had Wyoming waited for EPA's final RH FIP, none of these reductions would have occurred to date. In other words, the Wyoming RH SIP required regional haze reductions to begin earlier and extend over a longer period of time than EPA's RH FIP Action.

The following chart provides a graphical representation of the emission reductions



achieved as a result of the Wyoming RH SIP at PacifiCorp's BART Units.

For purposes of this graphic, the emissions reductions used are those that EPA identified in its Regional Haze FIP Action for the various technologies applied to each BART Unit by either Wyoming or EPA.

The solid blue line on the chart represents the annual NO_X emission reductions from PacifiCorp's units associated with the Wyoming RH plan. As the chart demonstrates, significant NO_X emissions reductions occurred between 2004 and 2012 under the state's plan. Additional NO_X reductions will occur under the state's plan as Naughton Unit 3 complies with the RH requirements, SCR is installed on Jim Bridger Unit 1 (2022), Unit 2 (2021), Unit 3 (2015) and Unit 4 (2016), and low NO_X burners are installed on Dave Johnston Unit 1 and Unit 2 as a part of the state's long-term reduction plan.

The solid orange line on the chart represents the NO_X emission reductions that would occur if no action were taken until EPA takes final action on its proposed FIP[58] (effectively no NO_X reductions until 2014). The blue hash-marked area on the chart represents the beneficial NO_X emissions that occur under the state's program, and the orange hash-marked area represents the beneficial NO_X emissions that occur under the EPA's FIP.

It is striking to note that from 2005-2021 the state's RH program will have removed 243,000 tons more NO_X from PacifiCorp's Wyoming facilities than EPA's proposed FIP. In 2022, the EPA's FIP begins providing an annual benefit of 5,100 tons per year. Ironically this benefit only lasts for six years, when the units at which EPA's proposed FIP requires more stringent controls are retired.

By 2027, the Wyoming RH SIP will have removed over 210,000 more tons of NO_X from PacifiCorp's units than the EPA's proposed FIP, with a significantly lower cost (more than $300M less in capital) and will require significantly lower expenditures in operation and maintenance between 2022 and 2027. Notwithstanding these significant NO_X emission reductions achieved by the Wyoming RH SIP, implementation of the Wyoming RH SIP has also resulted in significant reductions of SO_2 and particulate matter emissions.

Importantly, the Wyoming RH SIP appropriately balances all five BART factors, examining the reasonableness and timing of controls, in conjunction with management of planned outages, resource availability and other consequences of requiring costly emission controls. As discussed in Section 6 above, unlike the Wyoming RH SIP, the EPA's RH FIP requires controls that are not expected to be justifiable when aggregated and would result in accelerated unit retirements and replacements, potential natural gas conversions, and the associated costs and socio-economic impacts of removing major

[58] This chart has been created assuming that the Naughton Unit 3, Jim Bridger Unit 3 and Jim Bridger Unit 4 SCR projects would occur on the same schedule as that proposed by the state. In fact, this would not be possible had not all the planning and approvals already been received as a requirement of Wyoming's SIP.

coal-fueled generation resources from service in areas of Wyoming that rely heavily on these facilities.

As discussed herein, to date, PacifiCorp's actions to install control equipment on its BART Units in Wyoming have been taken in compliance with the Wyoming RH SIP and BART permits, along with the CAA, which requires major sources to "procure, install, and operate (BART) as expeditiously as practicable." CAA § 169A(b)(2)(A). Moreover, EPA chose not to participate in the Wyoming BART permit process and the resulting appeals, despite knowing that the very NO_X control equipment at issue in the RH FIP Action was being determined by Wyoming. As an alternative to the points made above, and under the principles of comity, EPA should be barred from now addressing these issues at this late period. "Under a statutory scheme which gives initial authority to a state agency, subject to approval of its recommendations by a federal agency, considerations of comity require the reviewing agency to consider the findings of the initiating agency." *The Cleveland Electric Illuminating Co. v. Environmental Protection Agency*, 603 F.2d 1 (6th Cir. 1979)(finding EPA acted arbitrarily and capriciously in rejecting Ohio's issuance of NPDES permits and for ignoring factors relied on by the state in approving the permits); *see also Ass'n of Irritated Residents v. US EPA,* 632 F.3d 584 (9th Cir. 2011)(holding EPA has an "affirmative duty" to evaluate information, including an older, approved SIP and that the agency does not have "unlimited discretion" to ignore evidence).

Moreover, unlike other programs, the regional haze program requires regular updates and reviews to ensure that reasonable progress is being made towards the ultimate goal ending in 2064. (*See* Attachment 14, June 26, 2012 Regional Haze hearing testimony by Steve Dietrich, Wyoming's Air Quality Administrator.) In fact, Wyoming will be required to submit a progress report to EPA in 2013 and a RH SIP update in 2018. *Id.* Wyoming's initial RH SIP addressing BART-eligible units was intended to be fully implemented by 2013 and was delayed solely by EPA's inaction. EPA should approve the Wyoming RH SIP, and reserve most of its concerns expressed in its RH FIP Action for consideration in Wyoming's 2018 RH SIP submittals. In the meantime, EPA can be assured that the significant emission reductions required under the Wyoming RH SIP, nearly all of which already have been installed, will continue to contribute to visibility improvement.

(11) <u>PacifiCorp's Response to EPA's Request for Control Technology Options.</u>

PacifiCorp recognizes that EPA has specifically requested under its RH FIP Action comments regarding "BART control technology option(s) that could be finalized either instead of, or in conjunction with, BART as proposed". *Id.* Considering the controls already installed on PacifiCorp's BART Units, the only control technologies available for consideration is SNCR or SCR. In this section PacifiCorp has updated the costs and cost effectiveness calculations. Any FIP determinations should be based on the information provided in this section. The ΔdV and days of impairment > 0.5 dV are from the models included in EPA's proposed FIP Action and do not reflect updated modeling.

After its review, PacifiCorp believes that Wyoming's BART determinations are correct. Nonetheless, PacifiCorp suggests the following control technology options as the less costly alternate solution to the EPA's proposed RH FIP. While the options discussed in this section provide NO_X emissions reductions greater than those achieved under the Wyoming RH SIP, the costs are too high to justify the benefits that will be achieved, especially when considering the additional information that PacifiCorp has presented in these comments. However, there is a significant reduction in the cost of compliance for these proposed alternatives when compared against EPA's proposed RH FIP. As stated above, PacifiCorp continues to believe that the Wyoming RH SIP is fully supportable and has been reasonably and appropriately established with the best interests of Wyoming and PacifiCorp's customers in mind.

Note: To facilitate the alternatives discussed for each unit, the proposed emission rates and emission reductions are those that EPA identified and utilized in the development of its proposed RH FIP. The identified visibility improvements are based on EPA's modeling and modeling results.

Control Technology for Naughton Units 1 and 2 - Naughton Unit 1 was retrofitted with low NO_X burners ("LNB") and separated over-fire air ("OFA") in early 2012, and Unit 2 was retrofitted with the same technology in late 2011. EPA recognizes that these units have a current annual NO_X emission rate of about 0.21 lb/MMBtu.

The potential additional NO_X controls that may be added to these units include SNCR and SCR. Tables 35 and 36 below provide additional information with respect to these specific control technologies for Naughton Units 1 and 2. The tables take into consideration the LNB/OFA controls that are required by the state SIP and already installed, as well as the updated information that PacifiCorp has provided in these comments.

The information presented in the tables further supports Wyoming's BART determination and RH SIP for Naughton Units 1 and 2; however, should an alternate control technology be prescribed by EPA for Naughton Units 1 and 2 in conjunction with EPA's RH FIP, SNCR is a preferable BART technology to SCR. Even though the cost of SNCR for each unit is unacceptably high (more than $9,600 per ton NO_X removed), it is still far less than the cost of SCR (approximately $14,000 for Unit 1, approximately $12,000 for Unit 2), particularly when taking into account the incrementally small modeled visibility improvement between the technologies. (*See* Attachments 3 and 15)

Table 34

	Naughton Unit 1 Alternate BART Control Technology Assessment (excludes AFUDC)							
Controls	**Annual Emission Rate (lb/mmBtu)**	**Emission Reduction (tpy)**	**Capital Costs**	**Annualized Costs**	**Cost Effectiveness ($/ton)**	**Incremental Cost Effectiveness ($/ton)**	**ΔdV for the max. 98th percentile improvement)**	**Annual Days of Impacts > 0.5 dV**
SNCR	0.16	363	$8,445,100	$3,516,265	$9,687	-----	0.15	9
SCR	0.05	1,108	$93,815,880	$15,659,686	$14,129	$16,293	0.39	4

Table 35

	Naughton Unit 2 Alternate BART Control Technology Assessment (excludes AFUDC)							
Controls	**Annual Emission Rate (lb/mmBtu)**	**Emission Reduction (tpy)**	**Capital Costs**	**Annualized Costs**	**Cost Effectiveness ($/ton)**	**Incremental Cost Effectiveness ($/ton)**	**ΔdV for the max. 98th percentile improvement)**	**Annual Days of Impacts > 0.5 dV**
SNCR	0.16	438	$8,761,397	$4,305,484	$9,830	-----	0.18	13
SCR	0.05	1,336	$93,251,860	$15,910,351	$11,913	$12,929	0.44	8

Compliance Alternative for Naughton Unit 3 –Rather than install the control equipment required by the Wyoming RH SIP, PacifiCorp will convert the unit to fire natural gas by the end of 2017. A construction permit allowing the conversion has been issued by Wyoming (included as Attachment 16), and PacifiCorp is moving ahead with a request for Wyoming to modify the Wyoming RH SIP to accommodate this change. The construction permit issued by Wyoming requires Naughton Unit 3 to cease burning coal by December 31, 2017 and to be retrofitted to natural gas as its fuel source by June 30, 2018. PacifiCorp requests that EPA's final RH FIP include this compliance alternative for Naughton Unit 3.

Control Technology for Dave Johnston Units 3 and 4 –Dave Johnston Unit 3 was retrofitted with LNB and separated OFA in the spring of 2010, and Unit 4 was retrofitted with the same technology in early 2009. EPA recognizes that Unit 3 has a current annual NO_X emission rate of about 0.22 lb/MMBtu, and Unit 4 has a rate of about 0.14 lb/MMBtu.

The potential additional NO_X controls that may be added to these units include SNCR and SCR. Tables 37 and 38 below provide additional information with respect to these specific control technologies for Dave Johnston Units 3 and 4. The tables take into consideration the LNB/OFA controls that are required by the state SIP and already installed, as well as the updated information that PacifiCorp has provided in these comments.

The information presented in the Tables 37 and 38 further supports Wyoming's BART determination and RH SIP for Dave Johnston Units 3 and 4. However, should an alternate control technology be considered by EPA for Dave Johnston Unit 3 in conjunction with EPA's RH FIP, SNCR is preferable to SCR for Dave Johnston Unit 3 when considering all currently available information and the current emissions performance of the unit. Even though the cost of SNCR is unacceptably high for Unit 3 (approximately $5,500 per ton NO_X removed), it is still far less than the tremendously expensive cost of SCR ($15,769 per ton NO_X removed for Unit 3), particularly when taking into account the incrementally small modeled visibility improvement between the technologies.

With respect to Dave Johnston Unit 4, EPA has concluded that SNCR is BART for that unit. As such, PacifiCorp has only provided updated SNCR information for Unit 4, considering all currently available information and the current emissions performance of the unit. The cost of SNCR for Unit 4 is unacceptably high and not cost effective (approximately $12,000 per ton NO_X removed) as shown below. (*See also* Attachments 3 and 15). The alternate control technology for Dave Johnston Unit 4 would be LNB/OFA, as is currently installed today.

Table 36

	Dave Johnston Unit 3 Alternate BART Control Technology Assessment (excludes AFUDC)							
Controls	**Annual Emission Rate (lb/mmBtu)**	**Emission Reduction (tpy)**	**Capital Costs**	**Annualized Costs**	**Cost Effectiveness ($/ton)**	**Incremental Cost Effectiveness ($/ton)**	**ΔdV for the max. 98th percentile improvement)**	**Annual Days of Impacts > 0.5 dV**
SNCR	0.16	519	$8,996,000	$2,880,289	$5,550	-----	0.12	8
SCR	0.05	1,596	$101,713,340	$19,495,711	$12,217	$15,431	0.36	1

Table 37

	Dave Johnston Unit 4 Alternate BART Control Technology Assessment (excludes AFUDC)							
Controls	**Annual Emission Rate (lb/mmBtu)**	**Emission Reduction (tpy)**	**Capital Costs**	**Annualized Costs**	**Cost Effectiveness ($/ton)**	**Incremental Cost Effectiveness ($/ton)**	**ΔdV for the max. 98th percentile improvement)**	**Annual Days of Impacts > 0.5 dV**
SNCR	0.16	391	$8,726,000	$4,624,769	$11,828	-----	0.11	9

<u>Alternate BART Control Technology for Jim Bridger Units 1 and 2</u> – As generally described in EPA's RH FIP Action, EPA is proposing that the time (i.e. compliance as prescribed by the Wyoming SIP by December 31, 2021, for Unit 2 and December 31, 2022, for Unit 1) to install SCR controls under the Wyoming's long term strategy for Jim Bridger Units 1 and 2 is warranted under the affordability provisions in the BART Appendix Y Guidelines. Considering that EPA's proposed RH FIP is generally aligned with the Wyoming SIP in this regard, PacifiCorp does not propose an alternative technology solution. As discussed earlier in PacifiCorp's comments, the affordability arguments that PacifiCorp made in its July 12, 2012 submittal referenced by EPA in its

RH FIP Action, as well as the additional information provided herein, remain applicable to this discussion and support the Wyoming RH SIP compliance timeline. This point becomes even more critical if EPA's final BART actions taken on the PacifiCorp units discussed above remains as currently proposed.

CONCLUSION

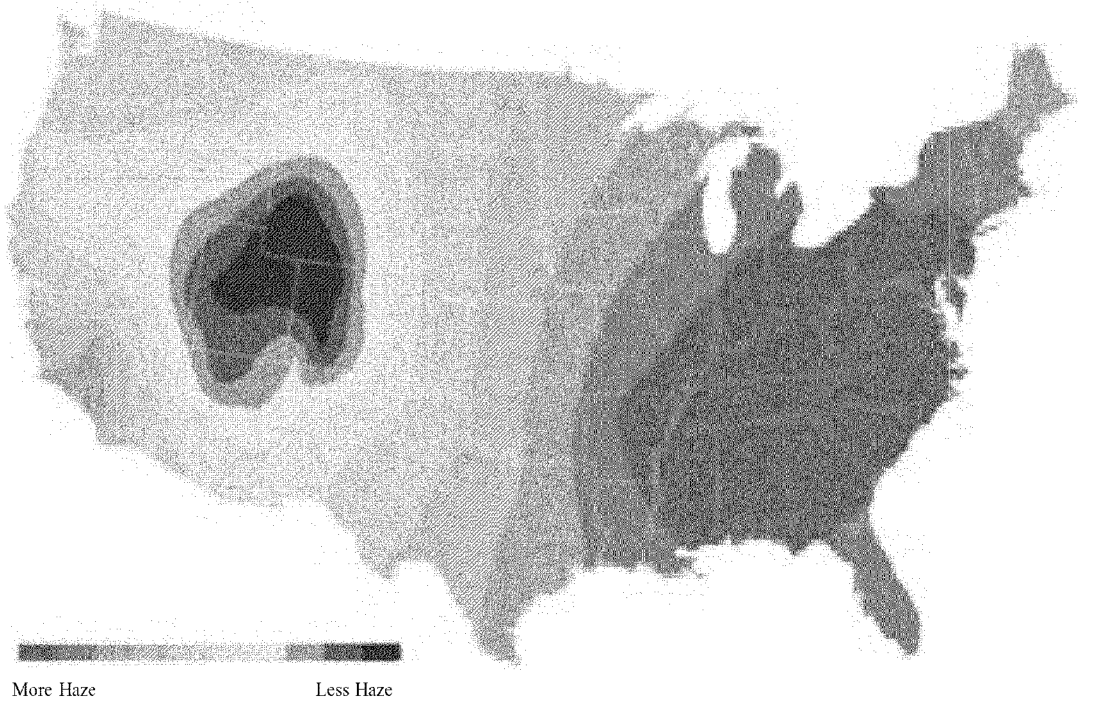
EPA's RH FIP Action distorts the Regional Haze program in an illegal attempt to attain some other goal, such as requiring post-combustion controls like SCR or SNCR on all western coal units, or attempting to assist with an unstated, undocumented and nebulous health concern. The Regional Haze program, however, is not a health-based program; rather, its sole focus is on aesthetics in Class 1 areas. 76 Fed. Reg. at 81,752 (noting that health issues are not considered "as part of the BART determination"). Additionally, the Regional Haze program's goal is to achieve "natural visibility" by 2064, 52 years from now. 40 C.F.R. § 51.308(d)(1)(i)(B).

Based on the foregoing, PacifiCorp encourages EPA to reconsider and withdraw its RH FIP and honor Wyoming's discretion under the CAA, Regional Haze Rules, Appendix Y, and Preamble by issuing a full approval of the Wyoming RH SIP.

Attachment 1

EPA-R8-2014-0028860001469

ATTACHMENT 1
EPA REGIONAL HAZE MAP



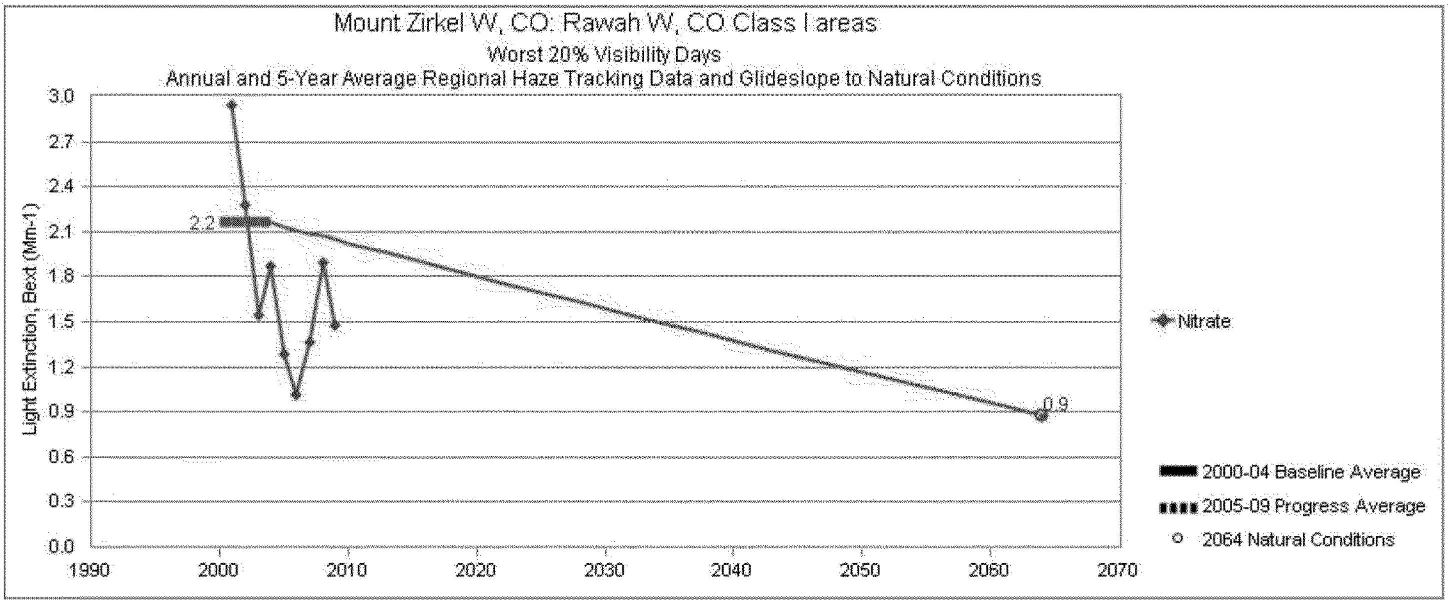
Haze conditions vary across the country. Eastern U.S. areas
Have more haze due to higher pollutant and humidity levels.

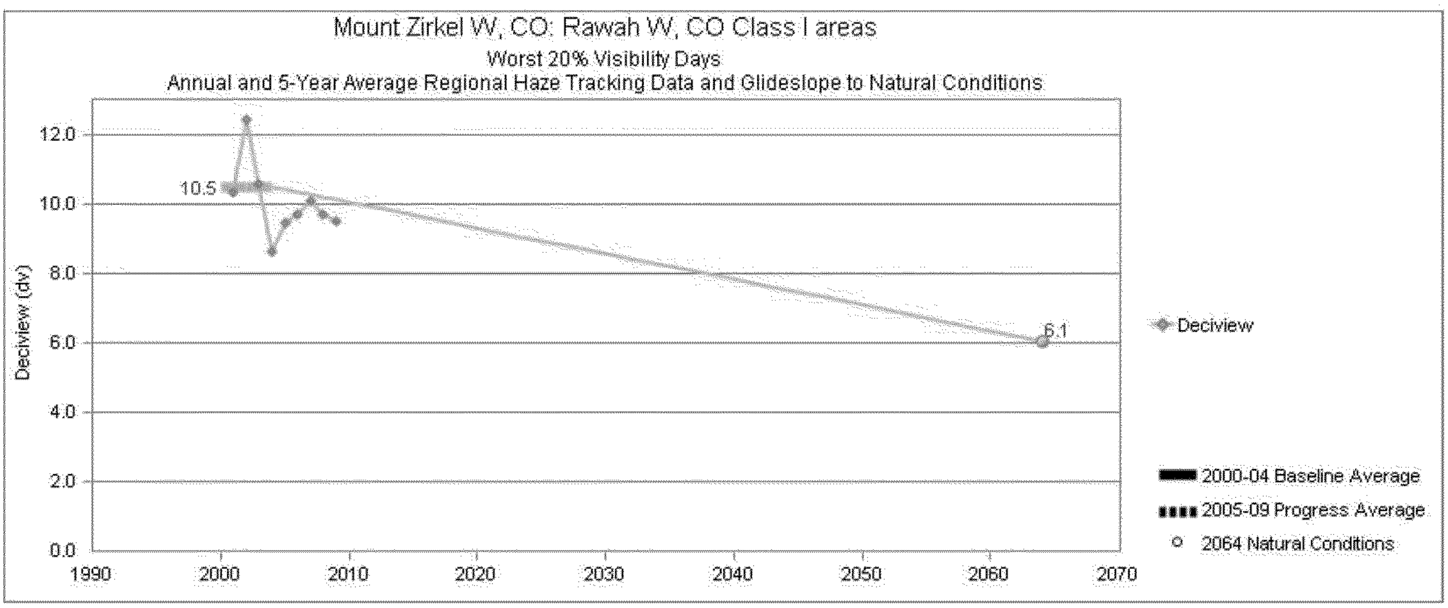
How Air Pollution Affects the View, http://www.epa.gov/oar/visibility/pdfs/haze_brocure_20060426.pdf

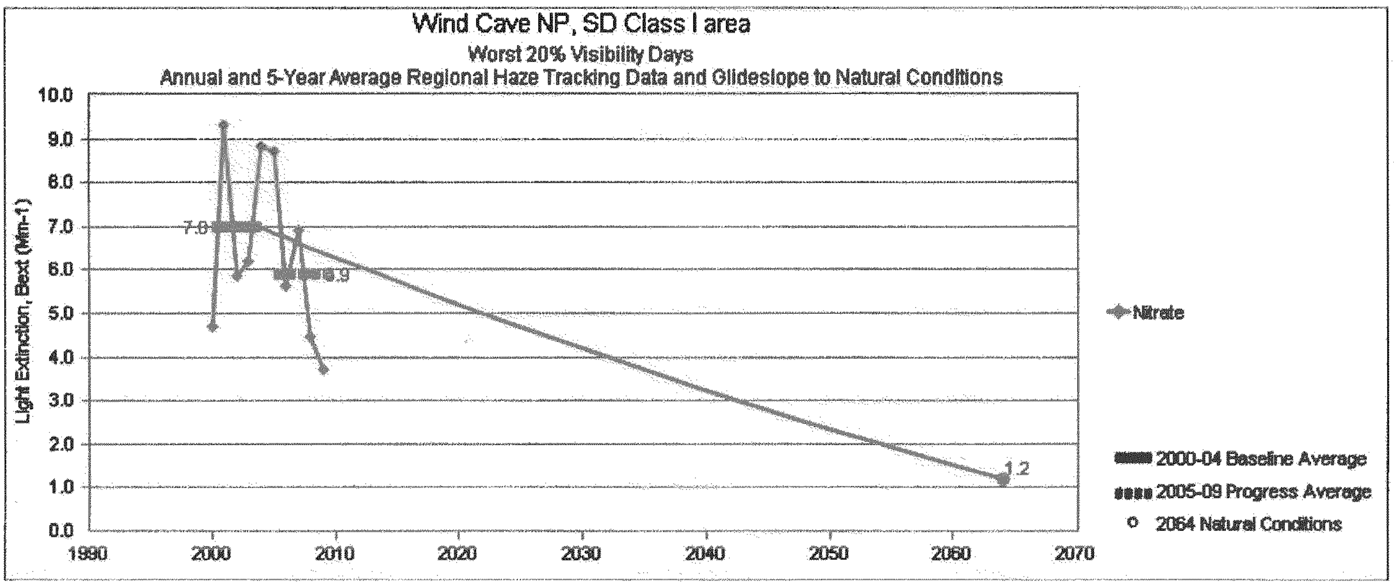
Attachment 2

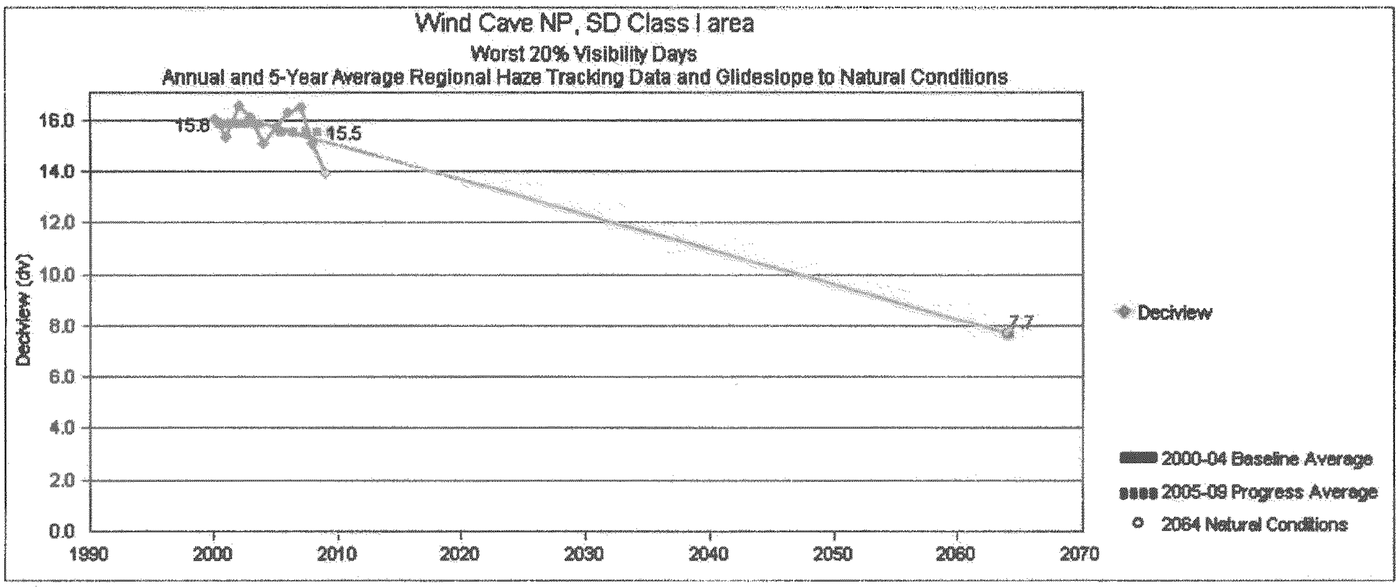
Monitored Visibility Impairment: Mt Zirkel & Wind Caves

Source of Data: http://vista.cira.colostate.edu/TSS/Results/HazePlanning.aspx






Wind Cave NP, SD Class I area
Worst 20% Visibility Days
Annual and 5-Year Average Regional Haze Tracking Data and Glideslope to Natural Conditions
Light Extinction, Bext (Mm-1)
7.0
5.9
1.2
Nitrate
2000-04 Baseline Average
2005-09 Progress Average
2064 Natural Conditions


Wind Cave NP, SD Class I area
Worst 20% Visibility Days
Annual and 5-Year Average Regional Haze Tracking Data and Glideslope to Natural Conditions
Deciview (dv)
15.8
15.5
7.7
Deciview
2000-04 Baseline Average
2005-09 Progress Average
2064 Natural Conditions

Attachment 3

Summary of Wyoming SIP Cost Effectiveness Calculations for PacifiCorp's Wyoming Units
(20-yr life / excluding AFUDC / WAQD emission rates)
PacifiCorp Comments

JIM BRIDGER 3

	Unit Characteristics		Control Technology Emissions		Control Technology Capital and O&M Costs								Dollars per Ton Removed	
Control Technologies	Unit Capacity (Net MW)	Unit Capacity Factor (%)	Annual Emission Rate (lb/MMBtu)	Baseline Emission Reductions (tons/yr)	Total Capital Costs	Depreciable Life (Years)	Capital Recovery Factor	Fixed O&M Costs ($/kw-yr)	Variable O&M Costs ($/MWH)	Annualized Capital Costs	1st Year O&M	Estimated Annual Control Costs	$/ton Removed	Incremental $ per Ton Removed
LNB/OFA Baseline	530	90.0%	0.26											
LNB with advanced OFA & & SNCR	530	90.0%	0.20	1,265	$9,952,239	20	9.51%			$946,458	$535,837	$1,482,295	$1,172	
LNB with advanced OFA & SCR	530	90.0%	0.07	4,006	$153,000,000	20	9.51%			$14,550,300	$3,370,460	$17,920,760	$4,474	
Incremental Costs	530	90.0%	0.13	2,741	$143,047,761	20	9.51%	$0.00	$0.00	$13,603,842	$2,834,623	$16,438,465		$5,998

JIM BRIDGER 4

	Unit Characteristics		Control Technology Emissions		Control Technology Capital and O&M Costs								Dollars per Ton Removed	
Control Technologies	Unit Capacity (Net MW)	Unit Capacity Factor (%)	Annual Emission Rate (lb/MMBtu)	Baseline Emission Reductions (tons/yr)	Total Capital Costs	Depreciable Life (Years)	Capital Recovery Factor	Fixed O&M Costs ($/kw-yr)	Variable O&M Costs ($/MWH)	Annualized Capital Costs	1st Year O&M	Estimated Annual Control Costs	$/ton Removed	Incremental $ per Ton Removed
LNB/OFA Baseline	530	90.0%	0.26											
LNB with advanced OFA & & SNCR	530	90.0%	0.20	1,231	$9,952,239	20	9.51%			$946,458	$535,837	$1,482,295	$1,204	
LNB with advanced OFA & SCR	530	90.0%	0.07	3,898	$153,000,000	20	9.51%			$14,550,300	$3,370,460	$17,920,760	$4,597	
Incremental Costs	530	90.0%	0.13	2,667	$143,047,761	20	9.51%	$0.00	$0.00	$13,603,842	$2,834,623	$16,438,465		$6,163

Summary of PacifiCorp's 2013 Cost Effectiveness Calculations for PacifiCorp's Wyoming Units
(remaining life / excluding AFUDC / EPA emission rates)
PacifiCorp Comments

DAVE JOHNSTON 3

Control Technologies	Unit Characteristics: Unit Capacity (Net MW)	Unit Characteristics: Unit Capacity Factor (%)	Control Technology Emissions: Annual Emission Rate (lb/MMBtu)	Control Technology Emissions: Baseline Emission Reductions (tons/yr)	Incremental Total Capital Costs	Depreciable Life (Years)	Capital Recovery Factor	Fixed O&M Costs ($/kw-yr)	Variable O&M Costs ($/MWH)	Annualized Capital Costs	1st Year O&M	Estimated Annual Control Costs	$/ton Removed	Incremental $ per Ton Removed
LNB/OFA (Baseline)	220	89.8%	0.22											
LNB with advanced OFA & & SNCR	220	89.8%	0.16	519	$8,996,000	9	16.55%	$1.48	$0.62	$1,488,838	$1,391,451	$2,880,289	$5,550	
LNB with advanced OFA & SCR	220	89.8%	0.05	1,596	$101,713,340	9						$19,495,711	$12,217	
Incremental Costs - SNCR to SCR	220	89.8%	0.11	1,077	$92,717,340	9						$16,615,422		$15,431

DAVE JOHNSTON 4

Control Technologies	Unit Characteristics: Unit Capacity (Net MW)	Unit Characteristics: Unit Capacity Factor (%)	Control Technology Emissions: Annual Emission Rate (lb/MMBtu)	Control Technology Emissions: Baseline Emission Reductions (tons/yr)	Incremental Total Capital Costs	Depreciable Life (Years)	Capital Recovery Factor	Fixed O&M Costs ($/kw-yr)	Variable O&M Costs ($/MWH)	Annualized Capital Costs	1st Year O&M	Estimated Annual Control Costs	$/ton Removed	Incremental $ per Ton Removed
LNB/OFA Baseline	330	87.4%	0.14											
LNB with advanced OFA & & SNCR	330	87.4%	0.11	391	$8,726,000	9	16.55%	$1.02	$1.13	$1,444,153	$3,180,616	$4,624,769	$11,828	

JIM BRIDGER 3

Control Technologies	Unit Characteristics: Unit Capacity (Net MW)	Unit Characteristics: Unit Capacity Factor (%)	Control Technology Emissions: Annual Emission Rate (lb/MMBtu)	Control Technology Emissions: Baseline Emission Reductions (tons/yr)	Incremental Total Capital Costs	Depreciable Life (Years)	Capital Recovery Factor	Fixed O&M Costs ($/kw-yr)	Variable O&M Costs ($/MWH)	Annualized Capital Costs	1st Year O&M	Estimated Annual Control Costs	$/ton Removed	Incremental $ per Ton Removed
LNB/OFA Baseline	530	87.2%	0.20											
LNB with advanced OFA & & SNCR	530	87.2%	0.16	829		20	10.64%			$0	$0	$0	$0	
LNB with advanced OFA & SCR	530	87.2%	0.05	3,089	$176,129,704	20	10.64%	$0.58	$0.59	$18,740,201	$2,654,500	$21,394,701	$6,926	
Incremental Costs - SNCR to SCR	530	87.2%	0.11	2,260	$176,129,704	20	10.64%	$0.58	$0.59	$18,740,201	$2,694,138	$21,434,339		$9,485

JIM BRIDGER 4

Control Technologies	Unit Characteristics: Unit Capacity (Net MW)	Unit Characteristics: Unit Capacity Factor (%)	Control Technology Emissions: Annual Emission Rate (lb/MMBtu)	Control Technology Emissions: Baseline Emission Reductions (tons/yr)	Incremental Total Capital Costs	Depreciable Life (Years)	Capital Recovery Factor	Fixed O&M Costs ($/kw-yr)	Variable O&M Costs ($/MWH)	Annualized Capital Costs	1st Year O&M	Estimated Annual Control Costs	$/ton Removed	Incremental $ per Ton Removed
LNB/OFA Baseline	530	84.4%	0.19											
LNB with advanced OFA & & SNCR	530	84.4%	0.15	795		20	10.64%			$0	$0	$0	$0	
LNB with advanced OFA & SCR	530	84.4%	0.05	2,946	$186,663,655	20	10.64%	$0.60	$0.61	$19,861,013	$2,654,500	$22,515,513	$7,642	
Incremental Costs - SNCR to SCR	530	84.4%	0.10	2,151	$186,663,655	20	10.64%	$0.60	$0.61	$19,861,013	$2,704,343	$22,565,356		$10,490

NAUGHTON 1

Control Technologies	Unit Characteristics: Unit Capacity (Net MW)	Unit Characteristics: Unit Capacity Factor (%)	Control Technology Emissions: Annual Emission Rate (lb/MMBtu)	Control Technology Emissions: Baseline Emission Reductions (tons/yr)	Incremental Total Capital Costs	Depreciable Life (Years)	Capital Recovery Factor	Fixed O&M Costs ($/kw-yr)	Variable O&M Costs ($/MWH)	Annualized Capital Costs	1st Year O&M	Estimated Annual Control Costs	$/ton Removed	Incremental $ per Ton Removed
LNB/OFA Baseline	160	90.7%	0.21											
LNB with advanced OFA & & SNCR	160	90.7%	0.16	363	$8,445,100	11	14.54%	$2.02	$1.55	$1,227,918	$2,288,348	$3,516,265	$9,687	
LNB with advanced OFA & SCR	160	90.7%	0.05	1,108	$93,815,880	11						$15,659,686	$14,129	
Incremental Costs - SNCR to SCR	160	90.7%	0.11	745	$85,370,780	11						$12,143,421		$16,293

NAUGHTON 2

Control Technologies	Unit Characteristics: Unit Capacity (Net MW)	Unit Characteristics: Unit Capacity Factor (%)	Control Technology Emissions: Annual Emission Rate (lb/MMBtu)	Control Technology Emissions: Baseline Emission Reductions (tons/yr)	Incremental Total Capital Costs	Depreciable Life (Years)	Capital Recovery Factor	Fixed O&M Costs ($/kw-yr)	Variable O&M Costs ($/MWH)	Annualized Capital Costs	1st Year O&M	Estimated Annual Control Costs	$/ton Removed	Incremental $ per Ton Removed
LNB/OFA Baseline	210	84.4%	0.21											
LNB with advanced OFA & & SNCR	210	84.4%	0.16	438	$8,761,397	11	14.54%	$1.66	$1.73	$1,273,907	$3,031,577	$4,305,484	$9,830	
LNB with advanced OFA & SCR	210	84.4%	0.05	1,336	$93,251,860	11						$15,910,351	$11,913	
Incremental Costs - SNCR to SCR	210	84.4%	0.11	898	$84,490,463	11						$11,604,867		$12,929

Attachment 4

Dave Johnston Unit 3

	B	C	D	E	F	G	I	J	K	L	M	N	O
2	NAME OF VARIABLE	VARIABLE	UNITS	EQUATION NUMBER	EQUATION	EXAMPLE PROBLEM VERBATIM	S&L CORRECTED EPA EXAMPLE	Comment	DAVE JOHNSTON 3 BASED ON CORRECTED EPA EXAMPLE WITH AMMONIA	Comment	DAVE JOHNSTON 3 BASED ON CORRECTED EPA EXAMPLE WITH UREA	Comment	DAVE JOHNSTON 3 BASED ON CORRECTED EPA EXAMPLE WITH ESCALATION AND WITH UREA
3													
4	Fuel High Heating Value	HHV	Btu/lb	-		10,000	10,000		10,000	Based on assumed typical DJ coal	10,000		10,000
5	Maximum Fuel Consumption Rate	$\dot{m}_{fuel}$	lb/hr	-	$\dot{m}_{fuel} = \frac{Q_B}{HHV}\times 10^6$	100,000	100,000		257,100	Calculated from maximum heat input and fuel high heating value	257,100		257,100
7	Max Generating Capacity		MW		$m_{fuel} = \frac{AnnualHeat\ Input}{HHV}\times 10^6$				230	Provided by PC	230		230
10	Average Number of Plant Operating Hours per Year		hr						7884	Estimated to achieve 90% capacity factor in Row 12	7884		7884
11	Number of SCR Operating Days	t(scr)	days	-		155	155		365	SCR operated year round	365		365
12	Plant Capacity Factor	CF_{plant}		-		50%	50%		90%	Operating hours divided by 8760	-		-
13	Uncontrolled NOx Concentration	NOx_{in}	lbNO2/MMBtu	-		0.86	0.86		0.27		0.27		0.27
14	NOx Concentration used for Reagent Consumption	NOx_{in}	lbNO2/MMBtu	-		0.86	0.86		0.27		0.27		0.27
15	Required Controlled NOx Concentration	NOx_{out}	lbNO2/MMBtu	-		0.13	0.13		0.07		0.07		0.07
16	Acceptable Ammonia Slip	Slip	ppm	-		2.00	2.00		2.00		2.00		2.00
17	Coal Type			-		Eastern Bituminous	Eastern Bituminous		Bituminous		Bituminous		Bituminous
18	Fuel Volumetric Flow Rate	q_{fuel}	ft³/min-MMBtu/hr	-		484.00	484.00		484.00		484.00		484.00
19	Fuel Heating Value		Btu/lb	-		12696.00	12696.00		-		-		-
20	Sulfur Content of Fuel	S	wt%	-		1.0	1.0		1.2		1.2		1.2
21	Fuel Ash Content	A	wt%	-		7.7%	7.7%		-		-		-
22	Actual Stoichiometric Ratio	ASR		-		1.05	1.05		1.05		1.05		1.05
23	Concentration of Reagent	C_{sol}	%	-		29%	29%		29%		50%	To account for a U2A system	50%
24	Days of Storage of Reagent	t	days	-		14.00	14.00		14.00		14.00		14.00
25	Pressure Drop for SCR Ductwork	ΔP_{duct}	in. w.g.	-		3.00	3.00		3.00		3.00		4.00
26	Pressure Drop for each Catalyst Layer	$\Delta P_{catalyst}$	in. w.g.	-		1.00	1.00		1.00		1.00		1.00
27	Number of SCR Reactors	N(scr)				1.00	1.00		1.00		1.00		1.00
28	Temperature at Reactor Inlet	T	°F	-		650.00	650.00		665.00		665.00		665.00
29													
30	Cost Year			-		Dec-98	Dec-98		Dec-98		Dec-98		Dec-98
31	Equipment Life	n	yr	-		20.00	20.00		20.00		20.00		20.00
32	Annual Interest Rate	i	-	-		7%	7%		7%		7%		7%
33	Chemical Engineering Plant Cost Index Value 1998												389.50
34	Chemical Engineering Plant Cost Index Value 2011												600.60
35	Catalyst Cost, Initial	$CC_{initial}$	\$/ft³	-		\$240.00	\$240.00		\$240.00		\$240.00		\$240.00
36	Catalyst Cost, Replacement	$CC_{replace}$	\$/ft³	-	$CC_{replace} = CC_{initial}(1.065)$	\$290.00	\$290.00		\$290.00		\$290.00		\$290.00
37	Electrical Power Cost	$Cost_{elect}$	\$/kWh	-		0.06	0.06		0.06		0.06		0.06
38	Reagent Cost	$Cost_{reagent}$	\$/lb	-	inc	0.101	0.101		0.101		0.200	Cost of Reagent adjusted to pricing for 5lb of Dry Urea	0.200
39	Operating Life of Catalyst	$h_{catalyst}$	hr	-		24,000	24,000		24,000		32,000	Based on PC target of 4 years operation cycle	32,000
40	Catalyst Layers Full	R_{layer}	#	-		2	2		3		3		3
41	Catalyst Layers Empty	R_{empty}	#	-		1	1		1	Empty layer for addition of extra catalyst layer in future to boost performance	1		1
42	Cost of Water		\$/1000-gal								5	Price of water per 1000 gallons	5
43													

	B	P	Q	R	S	T	U	V	W	X	Y	Z
2	NAME OF VARIABLE	Comment	DAVE JOHNSTON 3 BASED ON ANDOVER REPORT FEBRUARY 2013 (20-yr life / excluding AFUDC)	Comment	DAVE JOHNSTON 3 BASED ON VENDOR BUDGETARY PRICING (20-yr life / excluding AFUDC)	Comment	DAVE JOHNSTON 3 BASED ON VENDOR BUDGETARY PRICING (20-yr life / including AFUDC)	Comment	DAVE JOHNSTON 3 BASED ON ANDOVER REPORT FEBRUARY 2013 (9-yr life / excluding AFUDC)	Comment	DAVE JOHNSTON 3 BASED ON VENDOR BUDGETARY PRICING (9-yr life / excluding AFUDC)	Comment
3												
4	Fuel High Heating Value											
5	Maximum Fuel Consumption Rate											
7	Max Generating Capacity		220	As reported in Andover Report attachment.	220		220		220	As reported in Andover Report attachment	220	
10	Average Number of Plant Operating Hours per Year				7884		7884				7884	
11	Number of SCR Operating Days				365		365				365	
12	Plant Capacity Factor		89.8%	As reported in Andover Report attachment.	-		-		89.8%	As reported in Andover Report attachment.	-	
13	Uncontrolled NOx Concentration		0.22	As reported in Andover Report attachment.	0.22	Aligned with Andover Report assumption for cost-effectiveness comparison.	0.22	Aligned with Andover Report assumption for cost-effectiveness comparison.	0.22	As reported in Andover Report attachment.	0.22	Aligned with Andover Report assumption for cost-effectiveness comparison
14	NOx Concentration used for Reagent Consumption		0.22	As reported in Andover Report attachment.	0.22	Aligned with Andover Report assumption for reagent cost comparison.	0.22	Aligned with Andover Report assumption for reagent cost comparison.	0.22	As reported in Andover Report attachment	0.22	Aligned with Andover Report assumption for reagent cost comparison.
15	Required Controlled NOx Concentration		0.05	Based on 76.9% Removal used in Andover Report attachment.	0.05	Aligned with Andover Report assumption for comparison purposes.	0.05	Aligned with Andover Report assumption for comparison purposes.	0.05	Based on 76.9% Removal used in Andover Report attachment.	0.05	Aligned with Andover Report assumption for comparison purposes.
16	Acceptable Ammonia Slip				2.00		2.00				2.00	
17	Coal Type		PRB	As reported in Andover Report attachment.	Bituminous	Fuel at Naughton is actually Western Sub-bituminous, but this category not in Table 2.4	Bituminous	Fuel at Naughton is actually Western Sub-bituminous, but this category not in Table 2.4	PRB	As reported in Andover Report attachment	Bituminous	Fuel at Naughton is actually Western Sub-bituminous but this category not in Table 2.4
18	Fuel Volumetric Flow Rate					Not used, Vendor performed combustion calculation to arrive		Not used, Vendor performed combustion calculation to arrive				Not used, Vendor performed combustion calculation to arrive
19	Fuel Heating Value				-		-				-	
20	Sulfur Content of Fuel				1.2		1.2				1.2	
21	Fuel Ash Content				-		-				-	
22	Actual Stoichiometric Ratio				1.05		1.05				1.05	
23	Concentration of Reagent		50%	As reported in Andover Report attachment.	100%		100%		50%	As reported in Andover Report attachment.	100%	
24	Days of Storage of Reagent				14.00		14.00				14.00	
25	Pressure Drop for SCR Ductwork	More Typical for SCR systems			4.00		4.00				4.00	
26	Pressure Drop for each Catalyst Layer				1.00		1.00				1.00	
27	Number of SCR Reactors				1.00		1.00				1.00	
28	Temperature at Reactor Inlet				763.00		763.00				763.00	
29												
30	Cost Year											
31	Equipment Life	Year the Cost is Incurred			20.00		20.00		9.00		9.00	
32	Annual Interest Rate				7%		7%				7%	
33	Chemical Engineering Plant Cost Index Value 1998	Chemical Engineering Magazine Plant Cost Index value from 1998										
34	Chemical Engineering Plant Cost Index Value 2011	Chemical Engineering Magazine Plant Cost Index value from 2011										
35	Catalyst Cost, Initial					Included in Vendor Budgetary Pricing		Included in Vendor Budgetary Pricing				Included in Vendor Budgetary Pricing
36	Catalyst Cost, Replacement		\$155.74	Based on 5500 per m3 used in Andover Report attachment.	\$290.00		\$290.00		\$155.74	Based on 5500 per m3 used in Andover Report attachment	\$290.00	
37	Electrical Power Cost		0.06	As reported in Andover Report attachment	0.03	Price Provided by PC	0.03	Price Provided by PC	0.06	As reported in Andover Report attachment	0.03	Price Provided by PC
38	Reagent Cost		0.225	Based on 450 per tonused in Andover Report attachment	0.375	Price Provided by PC from DASCO quote July 2012	0.375	Price Provided by PC from DASCO quote July 2012	0.225	Based on 450 per tonused in Andover Report attachment	0.375	Price Provided by PC from DASCO quote July 2012
39	Operating Life of Catalyst				32,000		32,000				32,000	
40	Catalyst Layers Full				3		3				3	
41	Catalyst Layers Empty				1		1				1	
42	Cost of Water				5		5				5	
43												

	B	C	D	E	F	G	I	J	K	L	M
2	NAME OF VARIABLE	VARIABLE	UNITS	EQUATION NUMBER	EQUATION	EXAMPLE PROBLEM VERBATIM	S&L CORRECTED EPA EXAMPLE	Comment	DAVE JOHNSTON 3 BASED ON CORRECTED EPA EXAMPLE WITH AMMONIA	Comment	DAVE JOHNSTON 3 BASED ON CORRECTED EPA EXAMPLE WITH UREA
44											
47	Max Heat Input Rate	Q_B	MMBtu/hr	2.3	$Q_B = \frac{HHV \times \dot{m}_{fuel}}{10^6}$	1,000	1,000		2,571	Provided by PC	2,571
48	Plant Capacity Factor	CF_{plant}		2.7	$CF_{plant} = \frac{actual\ \dot{m}_{fuel}}{\dot{m}_{fuel} \times 8760}$	50%	50%		90%	90% from Permit Calculation	90%
49	SCR Capacity Factor	CF_{SCR}		2.8	$CF_{SCR} = \frac{t_{SCR}}{365\ days}$	42%	42%		100%		100%
50	Total Capacity Factor	CF_{total}		2.6	$CF_{total} = CF_{plant} \times CF_{SCR}$	27%	21%	Fixed EPA calculation error	90%		90%
51	Flue Gas Volumetric Flow Rate at Inlet/Reactor	$q_{flue\,gas}$	acfm	2.12	$q_{flue\,gas} = \frac{q_{fuel}\, Q_B\, (460 + T)}{(460 + 700°F)\, n_{SCR}}$	463,138	463,138		1,206,819		1,206,819
52	NOx Removal Efficient for Cost-Effectiveness					0.85	0.85		0.74		0.74
53	NOx Removal Efficiency for Reagent Consumption	η_{NO_x}		2.9	$\eta_{NO_x} = \frac{NO_{x_{in}} - NO_{x_{out}}}{NO_{x_{in}}}$	0.85	0.85		0.74		0.74
54											
55	Catalyst Volume/Reactor	$Vol_{catalyst}$	ft^3	2.19	$Vol_{catalyst} = 2.81 \times Q_B \times \eta_{adj} \times Slip_{adj} \times NO_{x_{adj}} \times S_{adj} \times \frac{T_{adj}}{N_{SCR}}$	5089	5089		9470		9470
56	where:	-	-	-							
57	NOx Efficiency Adjustment	η_{adj}		2.20	[illegible]	1.19	1.19		1.07		1.07
58	NOx Adjustment Factor for inlet NOx	NOx_{adj}		2.21	[illegible]	1.13	1.13		0.94		0.94
59	Ammonia Slip Adjustment Factor	$Slip_{adj}$		2.22	[illegible]	1.17	1.17		1.17		1.17
60	Sulfur in Coal Adjustment Factor	S_{adj}		2.23	[illegible]	1.01	1.01		1.02		1.02
61	Temperature Adjustment Factor (for temps other than 700°F)	T_{adj}	°F	2.24	$T_{adj} = 15.16 - (0.03937 \times T) + (2.74 \times 10^{-5} \times T^2)$	1.15	1.15		1.10		1.10
62											
63	Catalyst Cross-Sectional Area	$A_{catalyst}$	ft^2	2.25	$A_{catalyst} = \frac{q_{flue\,gas}}{16 \frac{ft}{sec} \times \frac{60\ sec}{min}}$	482	482		1257		1257
64	SCR Reactor Cross-Sectional Area	A_{SCR}	ft^2	2.26	$A_{SCR} = 1.15 \times A_{catalyst}$	554	554		1446		1446
65	length	l	ft	2.27	$l = w = (A_{SCR})^{1/2}$	23.50	23.50		38		38
66	width	w									
67	Estimate Number of Catalyst Layers	n_{layer}		2.28	$n_{layer} = \frac{Vol_{catalyst}}{3.1 \times A_{catalyst}}$	3	3	Estimated number of layers is less than input. Bypass this value and use input values instead for further calculations of h(layer) and n(total)	3	Estimated number of layers is too high. Bypass this value and use input values instead for further calculations of h(layer) and n(total)	3
68	Height of Catalyst Layer	h_{layer}	ft	2.29		4.50	4.50		3.50		3.50
69	Total Number of Catalyst Layers	n_{total}	#	2.30	$n_{total} = n_{layer} + n_{empty}$	4	4		4		4
70	Height of SCR Reactor	h_{SCR}	ft	2.31	$h_{SCR} = n_{total}(c_1 + h_{layer}) + c_2$	55	55		51		51

	B	N	O	P	Q	R	S	T	U	V	W	X	Y	Z
2	NAME OF VARIABLE	Comment	DAVE JOHNSTON 3 BASED ON CORRECTED EPA EXAMPLE WITH ESCALATION AND WITH UREA	Comment	DAVE JOHNSTON 3 BASED ON ANDOVER REPORT FEBRUARY 2013 (20-yr life / excluding AFUDC)	Comment	DAVE JOHNSTON 3 BASED ON VENDOR BUDGETARY PRICING (20-yr life / excluding AFUDC)	Comment	DAVE JOHNSTON 3 BASED ON VENDOR BUDGETARY PRICING (20-yr life / including AFUDC)	Comment	DAVE JOHNSTON 3 BASED ON ANDOVER REPORT FEBRUARY 2013 (9-yr life / excluding AFUDC)	Comment	DAVE JOHNSTON 3 BASED ON VENDOR BUDGETARY PRICING (9-yr life / excluding AFUDC)	Comment
44														
47	Max Heat Input Rate		2,571		2,440	As reported in Andover Report attachment.	2,571		2,571		2,440	As reported in Andover Report attachment.	2,571	
48	Plant Capacity Factor		90%		89.8%	As reported in Andover Report attachment.	90%		90%		89.8%	As reported in Andover Report attachment.	90%	
49	SCR Capacity Factor		100%				100%		100%				100%	
50	Total Capacity Factor		90%				90%		90%				90%	
51	Flue Gas Volumetric Flow Rate at Inlet/Reactor		1,206,819				1,842,000	Per Vendor's Combustion Calculation	1,842,000	Per Vendor's Combustion Calculation			1,842,000	Per Vendor's Combustion Calculation
52	NOx Removal Efficient for Cost-Effectiveness		0.74				0.77		0.77				0.77	
53	NOx Removal Efficiency for Reagent Consumption		0.74				0.77		0.77				0.77	
54														
55	Catalyst Volume/Reactor		9470		Unknown	Initial catalyst cost was not provided separately so estimated volume used by Andover unknown	25745	EPA cost manual shows catalyst volume is not a function of operating life, which is not valid. Estimated catalyst volumes were obtained by adjusting the Naughton 3 actual catalyst volumes for this unit. <u>This value is only used to estimate catalyst replacement costs because vendor pricing already includes initial catalyst cost.</u>	25745	EPA cost manual shows catalyst volume is not a function of operating life, which is not valid. Estimated catalyst volumes were obtained by adjusting the Naughton 3 actual catalyst volumes for this unit. <u>This value is only used to estimate catalyst replacement costs because vendor pricing already includes initial catalyst cost.</u>	Unknown	Initial catalyst cost was not provided separately so estimated volume used by Andover unknown	25745	EPA cost manual shows catalyst volume is not a function of operating life, which is not valid. Estimated catalyst volumes were obtained by adjusting the Naughton 3 actual catalyst volumes for this unit. <u>This value is only used to estimate catalyst replacement costs because vendor pricing already includes initial catalyst cost.</u>
56	where:													
57	NOx Efficiency Adjustment		1.07					Catalyst Cost in vendor estimate, this is not used.		Catalyst Cost in vendor estimate, this is not used.				Catalyst Cost in vendor estimate, this is not used.
58	NOx Adjustment Factor for inlet NOx		0.94					(see above)		(see above)				(see above)
59	Ammonia Slip Adjustment Factor		1.17					(see above)		(see above)				(see above)
60	Sulfur in Coal Adjustment Factor		1.02					(see above)		(see above)				(see above)
61	Temperature Adjustment Factor (for temps other than 700°F)		1.10					(see above)		(see above)				(see above)
62														
63	Catalyst Cross-Sectional Area		1257					(see above)		(see above)				(see above)
64	SCR Reactor Cross-Sectional Area		1446					(see above)		(see above)				(see above)
65	length		38					(see above)		(see above)				(see above)
66	width													
67	Estimate Number of Catalyst Layers	Estimated number of layers is too low. Bypass this value and use input values instead for further calculations of h(layer) and n(total)	3	Estimated number of layers is too high. Bypass this value and use input values instead for further calculations of h(layer) and n(total)				Included in vendor estimate, this input is not used.		Included in vendor estimate, this input is not used.				Included in vendor estimate, this input is not used.
68	Height of Catalyst Layer		3.50					Included in vendor estimate, this input is not used.		Included in vendor estimate, this input is not used.				Included in vendor estimate, this input is not used.
69	Total Number of Catalyst Layers		4				4		4				4	
70	Height of SCR Reactor		51					Included in vendor estimate, this input is not used.		Included in vendor estimate, this input is not used.				Included in vendor estimate, this input is not used.

	B	C	D	E	F	G	I	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y	Z
2	NAME OF VARIABLE	VARIABLE	UNITS	EQUATION NUMBER	EQUATION	EXAMPLE PROBLEM VERBATIM	S&L CORRECTED EPA EXAMPLE	Comment	DAVE JOHNSTON 3 BASED ON CORRECTED EPA EXAMPLE WITH AMMONIA	Comment	DAVE JOHNSTON 3 BASED ON CORRECTED EPA EXAMPLE WITH UREA	Comment	DAVE JOHNSTON 3 BASED ON CORRECTED EPA EXAMPLE WITH ESCALATION AND WITH UREA	Comment	DAVE JOHNSTON 3 BASED ON ANDOVER REPORT FEBRUARY 2013 (20-yr life / excluding AFUDC)	Comment	DAVE JOHNSTON 3 BASED ON VENDOR BUDGETARY PRICING (20-yr life / excluding AFUDC)	Comment	DAVE JOHNSTON 3 BASED ON VENDOR BUDGETARY PRICING (20-yr life / including AFUDC)	Comment	DAVE JOHNSTON 3 BASED ON ANDOVER REPORT FEBRUARY 2013 (9-yr life / excluding AFUDC)	Comment	DAVE JOHNSTON 3 BASED ON VENDOR BUDGETARY PRICING (9-yr life / excluding AFUDC)	Comment
71																								
72	Ammonia Mass Flow Rate	$m_{reagent}$	lb/hr of NH_3	2.32	$m_{reagent} = \frac{NO_{x_{in}} Q_B NSR \eta_{NO_x} M_{reagent}}{M_{NO_x} SR_r}$ $m_{reagent} = \frac{NOx_{in} \times Q_B \times ASR \times 17.03}{46.01}$	334	284	in the example problem (2.5 Example Problem). EPA does not use NOx efficiency in their calculation, yet the equation (2.32) on pg 2-39 requires it	200		200		200		159	Not in Andover report, but calculated from 100% Urea rate using 0.56 lb NH3 / lb of urea	170		170		159	Not in Andover report, but calculated from 100% Urea rate using 0.56 lb NH3 / lb of urea	170	
73	Mass Flow Rate of Aqueous Reagent Solution	$m_{solution}$	lb/hr of NH3 solution	2.33	$m_{sol} = \frac{m_{reagent}}{C_{sol}}$	1,153	980		689			Not used as urea is the reagent					170		170				170	
74	Equivalent Dry Urea Consumption Rate		lb/hr		$m_{urea} = \frac{m_{rl}}{0.56}$						357	S&L added formulas and calculations to include U2A system Value calculated for reagent costing	357		284						284			
75	Mass Flow Rate of Urea Solution	$m_{solution}$	lb/hr of NH3 solution	2.33	$m_{sol} = \frac{m_{reagent}}{C_{sol}}$						714		714		568		0		0		568		0	
76	Solution Volumetric Flow	q_{sol}	gph	2.34	$q_{sol} = \frac{m_{sol} \times 7.481}{71.1}$	154.00	131.00		92.00		75.00	Volumetric flow rate of 50% urea solution with a density of 71.1 lb/ft3	75.00		60		23.00		23.00		60		23.00	
77	Storage Tank Volume	V_{tank}	gal	2.35	[illegible]	51,744	44,016		30,912		25,200		25,200			Tank volume included in Andover estimate unknown	7,728		7,728			Tank volume included in Andover estimate unknown.	7,728	
78																								
80	Direct Capital Cost	DC	$	2.36		$6,832,000	$6,799,443		$12,265,691		$12,265,691		$20,768,412	Since no adjustment factor exists for urea systems S&L added the estimated capital cost for the urea system by scaling the Huntington estimate.	$51,756,152	As reported in Andover Report attachment	$72,100,000	From Vendor Budgetary Pricing for EPC contract. Information provided includes only Total Direct Costs (per item "A" from Table 2.5 in Cost Manual)	$72,100,000	From Vendor Budgetary Pricing for EPC contract. Information provided includes only Total Direct Costs (per item "A" from Table 2.5 in Cost Manual)	$51,756,152	As reported in Andover Report attachment	$72,100,000	From Vendor Budgetary Pricing for EPC contract. Information provided includes only Total Direct Costs (per item "A" from Table 2.5 in Cost Manual)
81	Adjustment for the SCR Reactor Height	$f(h_{SCR})$	$/MMBtu/hr	2.37	[illegible]	$149.00	$149.00		$124.00		$124.00		$124.00			Adjustment not used by Andover because EPA cost manual not followed		Covered in scaled estimate, this input is not used		Covered in scaled estimate, this input is not used.		Adjustment not used by Andover because EPA cost manual not followed		Covered in scaled estimate, this input is not used.
82	Adjustment for the Ammonia Flow Rate	$f(NH_{3rate})$	$/MMBtu/hr	2.38	[illegible]	$90.00	$89.00		-$15.00		-$15.00		-$15.00			Adjustment not used by Andover because EPA cost manual not followed		Covered in scaled estimate, this input is not used		Covered in scaled estimate, this input is not used.		Adjustment not used by Andover because EPA cost manual not followed		Covered in scaled estimate, this input is not used.
83	Adjustment for Retrofit or New Boiler	f(new)	$/MMBtu/hr	2.39 + 2.40	Is it a retrofit or new boiler?	$0.00	$0.00		$0.00		$0.00		$0.00			Adjustment not used by Andover because EPA cost manual not followed		Covered in scaled estimate, this input is not used.		Covered in scaled estimate, this input is not used.		Adjustment not used by Andover because EPA cost manual not followed		Covered in scaled estimate, this input is not used.
84	Adjustment for SCR Bypass	f(bypass)	$/MMBtu/hr	2.41 + 2.42	Is a bypass installed?	$0.00	$0.00		$0.00		$0.00		$0.00			Adjustment not used by Andover because EPA cost manual not followed		Covered in scaled estimate, this input is not used.		Covered in scaled estimate, this input is not used.		Adjustment not used by Andover because EPA cost manual not followed		Covered in scaled estimate, this input is not used.
85	Capital Cost for the Initial Charge of Catalyst	$f(Vol_{catalyst})$	$/MMBtu/hr	2.43	$f(Vol_{catalyst}) = Vol_{catalyst} \cdot CC_{initial}$	$1,221,360	$1,221,360		$2,272,800		$2,272,800		$2,272,800			Adjustment not used by Andover because EPA cost manual not followed		Covered in scaled estimate, this input is not used.		Covered in scaled estimate, this input is not used.		Adjustment not used by Andover because EPA cost manual not followed		Covered in scaled estimate, this input is not used.
86	Indirect Installation Costs Due to General Facilities		$	Table 2.5	0.05xDC	$341,600	$339,972		$613,285		$613,285		$1,038,421			Unknown because EPA cost manual not used	$3,605,000		$3,605,000			Unknown because EPA cost manual not used	$3,605,000	
87	Indirect Installation Costs Due to Engineering and Home Office Fees		$	Table 2.6	0.10xDC	$683,200	$679,944		$1,226,569		$1,226,569		$2,076,841			Unknown because EPA cost manual not used	$7,210,000		$7,210,000			Unknown because EPA cost manual not used	$7,210,000	
88	Indirect Installation Costs Due to Process Contingency		$	Table 2.7	0.05xDC	$341,600	$339,972		$613,285		$613,285		$1,038,421			Unknown because EPA cost manual not used	$3,605,000		$3,605,000			Unknown because EPA cost manual not used	$3,605,000	
89	Total Indirect Installation Costs	IIC	$	Table 2.8	DCx(0.05+0.10+0.05)	$1,366,400	$1,359,889		$2,453,138		$2,453,138		$4,153,682		$15,526,846	As reported in Andover Report attachment.	$14,420,000		$14,420,000		$15,526,846	As reported in Andover Report attachment.	$14,420,000	
90	Project Contingency		$	Table 2.9	(DC+IIC)x0.15	$1,229,760	$1,223,900		$2,207,824		$2,207,824		$3,738,314			Unknown because EPA cost manual not used	$12,978,000		$12,978,000			Unknown because EPA cost manual not used	$12,978,000	
91	Total Plant Costs	PC	$	Table 2.10	DC+IIC+Project Contingency	$9,428,160	$9,383,231		$16,926,653		$16,926,653		$28,660,408		$67,282,998		$99,498,000		$99,498,000		$67,282,998		$99,498,000	
92	Allowance for Funds During Construction	AFUDC	$												$0	As reported in Andover Report attachment.	$9,519,000	Estimated by S&L using a 7% Cost of Capital for SCR and proposed Naughton 3 cash flows. <u>Note that this value is not included in the TC, but is shown for information since this item does represent an actual cost to PacifiCorp.</u>	$9,519,000	Estimated by S&L using a 7% Cost of Capital for SCR and proposed Naughton 3 cash flows. <u>Included in the TC as an actual cost to PacifiCorp for comparative purposes.</u>	$0	As reported in Andover Report attachment.	$9,519,000	Estimated by S&L using a 7% Cost of Capital for SCR and proposed Naughton 3 cash flows. <u>Note that this value is not included in the TCI, but is shown for information since this item does represent an actual cost to PacifiCorp.</u>
93	Preproduction Cost	PrePro	$	Table 2.11	0.02 x (PC+Construction)	$188,563	$187,665		$338,533		$338,533		$573,208				$2,180,340		$2,180,340				$2,180,340	
94	Inventory Capital	Inventory	$	Table 2.12	m_{total} x days x 24 x inc	$39,128	$33,257		$23,382		$23,981		$23,981				$0	This item reflects urea only, which will not be part of capital costs. Other initial fills included in capital cost. Initial Catalyst Fills included as part of capital cost, therefore excluded in this item.	$0	This item reflects urea only, which will not be part of capital costs. Other initial fills included in capital cost. Initial Catalyst Fills included as part of capital cost, therefore excluded in this item.			$0	This item reflects urea only, which will not be part of capital costs. Other initial fills included in capital cost. Initial Catalyst Fills included as part of capital cost, therefore excluded in this item.
95	Initial Catalyst and Chemicals		$														$35,000		$35,000				$35,000	
96	**Total Capital Investment**	**TCI**	**$**	**Table 2.13**	**PC+Construction+PrePro+Inventory+Catalyst**	**$9,655,851**	**$9,604,153**		**$17,288,568**		**$17,289,167**		**$29,257,597**		**$67,282,997**	As reported in Andover Report attachment	**$101,713,340**		**$111,232,340**		**$67,282,997**	As reported in Andover Report attachment	**$101,713,340**	

	B	C	D	E	F	G	I	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y	Z
2	NAME OF VARIABLE	VARIABLE	UNITS	EQUATION NUMBER	EQUATION	EXAMPLE PROBLEM VERBATIM	S&L CORRECTED EPA EXAMPLE	Comment	DAVE JOHNSTON 3 BASED ON CORRECTED EPA EXAMPLE WITH AMMONIA	Comment	DAVE JOHNSTON 3 BASED ON CORRECTED EPA EXAMPLE WITH UREA	Comment	DAVE JOHNSTON 3 BASED ON CORRECTED EPA EXAMPLE WITH ESCALATION AND WITH UREA	Comment	DAVE JOHNSTON 3 BASED ON ANDOVER REPORT FEBRUARY 2013 (20-yr life / excluding AFUDC)	Comment	DAVE JOHNSTON 3 BASED ON VENDOR BUDGETARY PRICING (20-yr life / excluding AFUDC)	Comment	DAVE JOHNSTON 3 BASED ON VENDOR BUDGETARY PRICING (20-yr life / including AFUDC)	Comment	DAVE JOHNSTON 3 BASED ON ANDOVER REPORT FEBRUARY 2013 (9-yr life / excluding AFUDC)	Comment	DAVE JOHNSTON 3 BASED ON VENDOR BUDGETARY PRICING (9-yr life / excluding AFUDC)	Comment
97	Maintenance Cost		$/yr	2.46	$Annual\ Maintenance\ Cost = 0.015 \times TCI$	$144,838	$144,062		$259,329		$259,338		$438,864		$363,000	Based on $1.65/kw-yr as reported in Andover Report attachment.	$1,525,700		$1,668,485		$363,000	Based on $1.65/kw-yr as reported in Andover Report attachment.	$1,525,700	
98	Power	P	kW	2.48		444	444		999		999		1,134				1,126		1,126				1,126	
99	Electricity Cost		$/yr	2.49	[illegible] Annual Electricity Cost = Power × Cost [illegible]	$52,538	$41,316		$393,740		$393,740	Increase in power consumption for U2A system is negligible, thus no adjustment needed	$446,948	Increased due to additional pressure drop associated with ductwork	$623,025	Based on $0.36/MW-hr as reported in Andover Report attachment.	$286,253		$286,253		$623,025	Based on $0.36/MW-hr as reported in Andover Report attachment.	$286,253	
100	Reagent Solution Cost		$/yr	2.47	$ReagentCost = \frac{\dot{m}}{m_{sol}} \times 8760 \times CF_{total} \times Cost_{reagent}$	$275,435	$184,103		$548,640		$562,694		$562,694		$1,003,763	Based on $0.58/MW-hr as reported in Andover Report attachment.	$502,605		$502,605		$1,003,763	Based on $0.58/MW-hr as reported in Andover Report attachment.	$502,605	
101	Future Worth Factor	FWF		2.52	$FWF = i\left[\frac{1}{(1+i)^{Y}-1}\right]$	0.14	0.14		0.31		0.23		0.23				0.23		0.23				0.23	
102	Years	Y	yr	2.53	$Y = \frac{h_{catalyst}}{CF_{SCR} \times 8760}$	6	6		3		4		4				4		4				4	
103	Factor for Catalyst Replacement	R_{layer}				3	3		3		3		3				3		3				3	
104	Annual Catalyst Replacement Cost		$/yr	2.50 + 2.51	$AnnualCatalystReplacementCost = FWF \times 1 \times Vol_{catalyst} \times \frac{CC_{replace}}{R_{layer}}$	$68,871	$68,871		$283,784		$210,550		$210,550		$398,044	Based on $0.23/MW-hr as reported in Andover Report attachment.	$572,397	EPA formula excludes number of reactors. This formula has been updated to reflect catalyst in multiple reactors must be changed.	$572,397	EPA formula excludes number of reactors. This formula has been updated to reflect catalyst in multiple reactors must be changed.	$398,044	Based on $0.23/MW-hr as reported in Andover Report attachment.	$572,397	EPA formula excludes number of reactors. This formula has been updated to reflect catalyst in multiple reactors must be changed.
105	Annual Additional Water for Urea		$/yr		Volumetric flow rate of water, Dry Urea Consumption Rate * 1 lb H2O * 7.48 gal / (62.4 lb/ft3 * 1 lb urea)				$0		$1,686	Additional water would be needed for a U2A solid urea system in comparison with any other system because need the water to dissolve the solid urea. Value is based on gph flow rate of 50% urea solution.	$1,686			Not included in Andover Report attachment.	$0		$0			Not included in Andover Report attachment.	$0	
106	Annual Additional Steam for Urea Hydrolyzer		$/yr						$0		$84,404	Naughton 3 had 0.006MMBtu/hr of steam guaranteed per pound of urea consumed.	$84,404		$10,384	Based on $0.006/MW-hr as reported in Andover Report attachment.	$0		$0		$10,384	Based on $0.006/MW-hr as reported in Andover Report attachment.	$0	
107	Total Variable Direct Cost				=Electricity Cost+Reagent Solution Cost + Annual Catalyst Replacement Cost + Water Cost	$396,843	$294,290		$1,226,164		$1,253,074		$1,306,282		$2,035,216		$1,341,256		$1,341,258		$2,035,216		$1,341,256	
108	Total Direct Annual Cost			2.45	=Maintenance Cost +Total Variable Direct Cost	$541,681	$438,352		$1,485,493		$1,512,412		$1,745,146		$2,398,216		$3,884,089	+ Property Tax Factor PacifiCorp is subject to property taxes, per EPA cost manual 0.01*TCI was used.	$4,122,064	+ Property Tax Factor PacifiCorp is subject to property taxes, per EPA cost manual 0.01*TCI was used.	$2,398,216		$3,884,089	+ Property Tax Factor PacifiCorp is subject to property taxes per EPA cost manual 0.01*TCI was used.
109	Property Tax Factor	F(tax)		2.5.5.8		0.00	0.00		0.00		0.00		0.00				$1,017,133		$1,112,323				$1,017,133	
110	Overhead Factor	F(ovhd)				0.00	0.00		0.00		0.00		0.00				0.00		0.00				0.00	
111	Capital Recovery Factor	CRF		2.55	$CRF = \frac{i(1+i)^{n}}{(1+i)^{n}-1}$	0.0944	0.0944		0.0944		0.0944		0.0944		0.1064	Based on a capital recovery factor of 9.44% and a property taxes and insurance rate of 1.20%, Total Charge Rate = 10.64%.	0.0944		0.0944		0.1655	Based on a capital recovery factor of 9.44% and a property taxes and insurance rate of 1.20%. Total Charge Rate = 10.64%.	0.1535	
112	Indirect Annual Costs	IDAC	$/yr	2.54	$IDAC = CRF \times TCI$	$911,444	$906,564		$1,631,919		$1,631,975		$2,761,710		$7,158,911		$9,601,020		$10,499,546		$11,135,336		$15,611,622	
113	Total Annual Cost	TAC	$/yr	2.56	[illegible]	**$1,453,125**	**$1,344,916**		**$3,117,411**		**$3,144,387**		**$4,506,857**		**$9,562,381**	As reported in Andover Report attachment.	**$13,485,109**		**$14,621,610**		**$13,533,552**	As reported in Andover Report attachment.	**$19,495,711**	
114	Annual NOx Removed		tons/yr	2.57	NOx Removed [illegible]	864	680		2,025		2,025		2,025		1,597	As reported in Andover Report attachment.	1,597	Aligned with Andover Report assumption for cost-effectiveness comparison.	1,597	Aligned with Andover Report assumption for cost-effectiveness comparison.	1,597	As reported in Andover Report attachment.	1,597	Aligned with Andover Report assumption for cost-effectiveness comparison.
115	Cost Effectiveness		$/ton	2.58	$Cost\ Effectiveness = \frac{TAC}{NO_x\ Removed}$	**$1,681**	**$1,978**		**$1,540**		**$1,553**		**$2,226**		**$5,989**	**As reported in Andover Report attachment.**	**$8,444**		**$9,156**		**$8,474**	**As reported in Andover Report attachment.**	**$12,208**	

116 **Note 1 - In attachment EPA-R08-OAR-2012-0026-0087, Andover calculates SCR cost effectiveness in two ways: a) starting from baseline emissions of 0.22, assuming combustion controls already in place (see worksheet "NOx - SCR_01_03")and b) starting from baseline emissions of 0.52, assuming combustion controls are not in place (see worksheet "Dave Johnston"). This worksheet reports Andover's results assuming combustion controls are already in place since this is consistent with current operation at Dave Johnston.**

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Naughton Unit 1

	B	C	D	E	F	G	I	J	K	L	M	N	O
2	NAME OF VARIABLE	VARIABLE	UNITS	EQUATION NUMBER	EQUATION	EXAMPLE PROBLEM VERBATIM	S&L CORRECTED EPA EXAMPLE	Comment	NAUGHTON 1 BASED ON CORRECTED EPA EXAMPLE WITH AMMONIA	Comment	NAUGHTON 1 BASED ON CORRECTED EPA EXAMPLE WITH UREA	Comment	NAUGHTON 1 BASED ON CORRECTED EPA EXAMPLE WITH ESCALATION AND WITH UREA
3													
4	Fuel High Heating Value	HHV	Btu/lb	-		10,000	10,000		10,000	Based on typical Naughton coal	10,000		10,000
5	Maximum Fuel Consumption Rate	$\dot{m}_{fuel}$	lb/hr	-	$\dot{m}_{fuel} = \frac{Q_B}{HHV} \times 10^6$	100,000	100,000		171,900	Calculated from maximum heat input and fuel high heating value	171,900		171,900
7	Max Generating Capacity		MW		$m_{fuel} = \frac{AnnualHeat\ \ Input}{HHV} \times 10^6$				160	Provided by PC	160		160
10	Average Number of Plant Operating Hours per Year		hr						7884	Estimated to achieve 90% capacity factor in Row 12	7884		7884
11	Number of SCR Operating Days	t(scr)	days	-		155	155		365	SCR operated year round	365		365
12	Plant Capacity Factor	CF_{plant}		-		50%	50%		90%	Operating hours divided by 8760	-		-
13	Uncontrolled NOx Concentration	NOx_{in}	lbNO2/MMBtu	-		0.86	0.86		0.26		0.26		0.26
14	NOx Concentration used for Reagent Consumption	NOx_{in}	lbNO2/MMBtu	-		0.86	0.86		0.26		0.26		0.26
15	Required Controlled NOx Concentration	NOx_{out}	lbNO2/MMBtu	-		0.13	0.13		0.07		0.07		0.07
16	Acceptable Ammonia Slip	Slip	ppm	-		2.00	2.00		2.00		2.00		2.00
17	Coal Type			-		Eastern Bituminous	Eastern Bituminous		Bituminous		Bituminous		Bituminous
18	Fuel Volumetric Flow Rate	q_{fuel}	ft^3/min-MMBtu/hr	-		484.00	484.00		484.00		484.00		484.00
19	Fuel Heating Value		Btu/lb	-		12896.00	12896.00		-		-		-
20	Sulfur Content of Fuel	S	wt%	-		1.0	1.0		1.2		1.2		1.2
21	Fuel Ash Content	A	wt%	-		7.7%	7.7%		-		-		-
22	Actual Stoichiometric Ratio	ASR		-		1.05	1.05		1.05		1.05		1.05
23	Concentration of Reagent	C_{sol}	%	-		29%	29%		29%		50%	To account for a U2A system	50%
24	Days of Storage of Reagent	t	days	-		14.00	14.00		14.00		14.00		14.00
25	Pressure Drop for SCR Ductwork	ΔP_{duct}	in. w.g.	-		3.00	3.00		3.00		3.00		4.00
26	Pressure Drop for each Catalyst Layer	$\Delta P_{catalyst}$	in. w.g.	-		1.00	1.00		1.00		1.00		1.00
27	Number of SCR Reactors	N(scr)				1.00	1.00		1.00		1.00		1.00
28	Temperature at Reactor Inlet	T	°F	-		650.00	650.00		665.00		665.00		665.00
29													
30	Cost Year			-		Dec-98	Dec-98		Dec-98		Dec-98		Dec-98
31	Equipment Life	n	yr	-		20.00	20.00		20.00		20.00		20.00
32	Annual Interest Rate	i		-		7%	7%		7%		7%		7%
33	Chemical Engineering Plant Cost Index Value 1998												389.50
34	Chemical Engineering Plant Cost Index Value 2011												600.60
35	Catalyst Cost, Initial	$CC_{initial}$	$/$ft^3$	-		$240.00	$240.00		$240.00		$240.00		$240.00
36	Catalyst Cost Replacement	$CC_{replace}$	$/$ft^3$	-	$CC_{replace} = CC_{initial}(1.065)^y$	$290.00	$290.00		$290.00		$290.00		$290.00
37	Electrical Power Cost	$Cost_{elect}$	$/kWh	-		0.05	0.05		0.05		0.05		0.05
38	Reagent Cost	$Cost_{reagent}$	$/lb	-	irc	0.101	0.101		0.101		0.200	Cost of Reagent adjusted to pricing for $/lb of Dry Urea	0.200
39	Operating Life of Catalyst	$h_{catalyst}$	hr	-		24,000	24,000		24,000		32,000	Based on PC target of 4-year operation cycle	32,000
40	Catalyst Layers Full	n_{layer}	#	-		2	2		3		3		3
41	Catalyst Layers Empty	n_{empty}	#	-		1	1		1	Empty layer for addition of extra catalyst layer in future to boost performance	1		1
42	Cost of Water		$/1000-gal								5	Price of water per 1000 gallons	5
43													

	B	P	Q	R	S	T	U	V	W	X	Y	Z
2	NAME OF VARIABLE	Comment	NAUGHTON 1 BASED ON ANDOVER REPORT FEBRUARY 2013 (20-yr life / excluding AFUDC)	Comment	NAUGHTON 1 BASED ON VENDOR BUDGETARY PRICING (20-yr life / excluding AFUDC)	Comment	NAUGHTON 1 BASED ON VENDOR BUDGETARY PRICING (20-yr life / including AFUDC)	Comment	NAUGHTON 1 BASED ON ANDOVER REPORT FEBRUARY 2013 (11-yr life / excluding AFUDC)	Comment	NAUGHTON 1 BASED ON VENDOR BUDGETARY PRICING (11-yr life / excluding AFUDC)	Comment
3												
4	Fuel High Heating Value											
5	Maximum Fuel Consumption Rate											
7	Max Generating Capacity		160	As reported in Andover Report attachment.	160		160		160	As reported in Andover Report attachment	160	
10	Average Number of Plant Operating Hours per Year				7884		7884				7884	
11	Number of SCR Operating Days				365		365				365	
12	Plant Capacity Factor		90.7%	As reported in Andover Report attachment.	-		-		90.7%	As reported in Andover Report attachment.	-	
13	Uncontrolled NOx Concentration		0.21	As reported in Andover Report attachment.	0.21	Aligned with Andover Report assumption for cost-effectiveness comparison.	0.21	Aligned with Andover Report assumption for cost-effectiveness comparison.	0.21	As reported in Andover Report attachment.	0.21	Aligned with Andover Report assumption for cost-effectiveness comparison.
14	NOx Concentration used for Reagent Consumption		0.21	As reported in Andover Report attachment.	0.21	Aligned with Andover Report assumption for reagent cost comparison.	0.21	Aligned with Andover Report assumption for reagent cost comparison.	0.21	As reported in Andover Report attachment.	0.21	Aligned with Andover Report assumption for reagent cost comparison
15	Required Controlled NOx Concentration		0.05	Based on 76.3% Removal used in Andover Report attachment.	0.05	Aligned with Andover Report assumption for comparison purposes.	0.05	Aligned with Andover Report assumption for comparison purposes.	0.05	Based on 76.3% Removal used in Andover Report attachment.	0.05	Aligned with Andover Report assumption for comparison purposes.
16	Acceptable Ammonia Slip				2.00		2.00				2.00	
17	Coal Type		PRB	As reported in Andover Report attachment.	Bituminous	Fuel at Naughton is actually Western Sub-bituminous, but this category not in Table 2.4	Bituminous	Fuel at Naughton is actually Western Sub-bituminous, but this category not in Table 2.4	PRB	As reported in Andover Report attachment.	Bituminous	Fuel at Naughton is actually Western Sub-bituminous, but this category not in Table 2.4
18	Fuel Volumetric Flow Rate					Not used, Vendor performed combustion calculation to arrive at volume		Not used, Vendor performed combustion calculation to arrive at volume				Not used, Vendor performed combustion calculation to arrive at volume
19	Fuel Heating Value				-		-				-	
20	Sulfur Content of Fuel				1.2		1.2				1.2	
21	Fuel Ash Content				-		-				-	
22	Actual Stoichiometric Ratio				1.05		1.05				1.05	
23	Concentration of Reagent		50%	As reported in Andover Report attachment	100%		100%		50%	As reported in Andover Report attachment	100%	
24	Days of Storage of Reagent				14.00		14.00				14.00	
25	Pressure Drop for SCR Ductwork	More Typical for SCR systems			4.00		4.00				4.00	
26	Pressure Drop for each Catalyst Layer				1.00		1.00				1.00	
27	Number of SCR Reactors				1.00		1.00				1.00	
28	Temperature at Reactor Inlet				763.00		763.00				763.00	
29												
30	Cost Year											
31	Equipment Life	Year the Cost is Incurred			20.00		20.00		11.00		11.00	
32	Annual Interest Rate				7%		7%				7%	
33	Chemical Engineering Plant Cost Index Value 1998	Chemical Engineering Magazine Plant Cost Index value from 1998										
34	Chemical Engineering Plant Cost Index Value 2011	Chemical Engineering Magazine Plant Cost Index value from 2011										
35	Catalyst Cost, Initial					Included in Vendor Budgetary Pricing		Included in Vendor Budgetary Pricing				Included in Vendor Budgetary Pricing
36	Catalyst Cost Replacement		$155.74	Based on 5500 per m3 used in Andover Report attachment.	$290.00		$290.00		$155.74	Based on 5500 per m3 used in Andover Report attachment.	$290.00	
37	Electrical Power Cost		0.06	As reported in Andover Report attachment.	0.03	Price Provided by PC	0.03	Price Provided by PC	0.06	As reported in Andover Report attachment.	0.03	Price Provided by PC
38	Reagent Cost		0.225	Based on 450 per tonused in Andover Report attachment.	0.375	Price Provided by PC from DASCO quote July 2012	0.375	Price Provided by PC from DASCO quote July 2012	0.225	Based on 450 per tonused in Andover Report attachment.	0.375	Price Provided by PC from DASCO quote July 2012
39	Operating Life of Catalyst				32,000		32,000				32,000	
40	Catalyst Layers Full				3		3				3	
41	Catalyst Layers Empty				1		1				1	
42	Cost of Water				5		5				5	
43												

	B	C	D	E	F	G	I	J	K	L	M	N
2	NAME OF VARIABLE	VARIABLE	UNITS	EQUATION NUMBER	EQUATION	EXAMPLE PROBLEM VERBATIM	S&L CORRECTED EPA EXAMPLE	Comment	NAUGHTON 1 BASED ON CORRECTED EPA EXAMPLE WITH AMMONIA	Comment	NAUGHTON 1 BASED ON CORRECTED EPA EXAMPLE WITH UREA	Comment
44												
47	Max Heat Input Rate	Q_B	MMBtu/hr	2.3	$Q_B = \frac{HV \times m_{fuel}}{10^6}$	1,000	1,000		1,719	Provided by PC	1,719	
48	Plant Capacity Factor	CF_{plant}		2.7	$CF_{plant} = \frac{actual\ m_{fuel}}{m_{fuel} \times 8760}$	50%	50%		90%	90% from Permit Calculation	90%	
49	SCR Capacity Factor	CF_{SCR}		2.8	$CF_{SCR} = \frac{t_{SCR}}{365\ days}$	42%	42%		100%		100%	
50	Total Capacity Factor	CF_{total}		2.6	$CF_{total} = CF_{plant} \times CF_{SCR}$	27%	21%	Fixed EPA calculation error	90%		90%	
51	Flue Gas Volumetric Flow Rate at Inlet/Reactor	$q_{flue\ gas}$	acfm	2.12	$q_{flue\ gas} = \frac{q_{fuel}\, Q_B\, (460 + T)}{(460 + 700°F)\, n_{SCR}}$	463,138	463,138		806,893		806,893	
52	NOx Removal Efficient for Cost-Effectiveness					0.85	0.85		0.73		0.73	
53	NOx Removal Efficiency for Reagent Consumption	η_{NO_x}		2.9	$\eta_{NO_x} = \frac{NO_{x_{in}} - NO_{x_{out}}}{NO_{x_{in}}}$	0.85	0.85		0.73		0.73	
54												
55	Catalyst Volume/Reactor	$Vol_{catalyst}$	ft^3	2.19	$Vol_{catalyst} = 2.81 \times Q_B \times \eta_{adj} \times Slip_{adj} \times NO_{x_{adj}} \times S_{adj} \times \frac{T_{adj}}{N_{SCR}}$	5089	5089		6248		6248	
56	where:	-	-	-								
57	NOx Efficiency Adjustment	η_{adj}		2.20	$\eta_{adj} = 0.2869 + (1.058 \times \eta)$	1.19	1.19		1.06		1.06	
58	NOx Adjustment Factor for inlet NOx	$NO_{x_{adj}}$		2.21	$NO_{x_{adj}} = 0.8524 + (0.3208 \times NO_{x_{in}})$	1.13	1.13		0.94		0.94	
59	Ammonia Slip Adjustment Factor	$Slip_{adj}$		2.22	$Slip_{adj} = 1.2835 - (0.0567 \times Slip)$	1.17	1.17		1.17		1.17	
60	Sulfur in Coal Adjustment Factor	S_{adj}		2.23	$S_{adj} = 0.9636 + (0.0455 \times S)$	1.01	1.01		1.02		1.02	
61	Temperature Adjustment Factor (for temps other than 700°F)	T_{adj}	°F	2.24	$T_{adj} = 15.16 - (0.03937 \times T) + (2.74 \times 10^{-5} \times T^2)$	1.15	1.15		1.10		1.10	
62												
63	Catalyst Cross-Sectional Area	$A_{catalyst}$	ft^2	2.25	$A_{catalyst} = \frac{q_{flue\ gas}}{16 \frac{ft}{sec} \times \frac{60\ sec}{min}}$	482	482		841		841	
64	SCR Reactor Cross-Sectional Area	A_{SCR}	ft^2	2.26	$A_{SCR} = 1.15 \times A_{catalyst}$	554	554		967		967	
65	length	l	ft	2.27	$l = w = (A_{SCR})^{0.5}$	23.50	23.50		31		31	
66	width	w										
67	Estimate Number of Catalyst Layers	n_{layer}		2.28	$n_{layer} = \frac{Vol_{catalyst}}{3.1 \times A_{catalyst}}$	3	3	Estimated number of layers is less than input. Bypass this value and use input values instead for further calculations of h(layer) and n(total)	3	Estimated number of layers is too high. Bypass this value and use input values instead for further calculations of h(layer) and n(total)	3	Estimated number of layers is too low. Bypass this value and use input values instead for further calculations of h(layer) and n(total)
68	Height of Catalyst Layer	h_{layer}	ft	2.29		4.50	4.50		3.50		3.50	
69	Total Number of Catalyst Layers	n_{total}	#	2.30	$n_{total} = n_{layer} + n_{empty}$	4	4		4		4	
70	Height of SCR Reactor	h_{SCR}	ft	2.31	$h_{SCR} = n_{total}(c_1 + h_{layer}) + c_2$	55	55		51		51	

	B	O	P	Q	R	S	T	U	V	W	X	Y	Z
2	NAME OF VARIABLE	NAUGHTON 1 BASED ON CORRECTED EPA EXAMPLE WITH ESCALATION AND WITH UREA	Comment	NAUGHTON 1 BASED ON ANDOVER REPORT FEBRUARY 2013 (20-yr life / excluding AFUDC)	Comment	NAUGHTON 1 BASED ON VENDOR BUDGETARY PRICING (20-yr life / excluding AFUDC)	Comment	NAUGHTON 1 BASED ON VENDOR BUDGETARY PRICING (20-yr life / including AFUDC)	Comment	NAUGHTON 1 BASED ON ANDOVER REPORT FEBRUARY 2013 (11-yr life / excluding AFUDC)	Comment	NAUGHTON 1 BASED ON VENDOR BUDGETARY PRICING (11-yr life / excluding AFUDC)	Comment
44													
47	Max Heat Input Rate	1,719		1,740	As reported in Andover Report attachment.	1,719		1,719		1,740	As reported in Andover Report attachment	1,719	
48	Plant Capacity Factor	90%		90.7%	As reported in Andover Report attachment.	90%		90%		90.7%	As reported in Andover Report attachment.	90%	
49	SCR Capacity Factor	100%				100%		100%				100%	
50	Total Capacity Factor	90%				90%		90%				90%	
51	Flue Gas Volumetric Flow Rate at Inlet/Reactor	806,893				1,188,000	Per Vendor's Combustion Calculation	1 188 000	Per Vendor's Combustion Calculation			1 188,000	Per Vendor's Combustion Calculation
52	NOx Removal Efficient for Cost-Effectiveness	0.73				0.76		0.76				0.76	
53	NOx Removal Efficiency for Reagent Consumption	0.73				0.76		0.76				0.76	
54													
55	Catalyst Volume/Reactor	6248		Unknown	Initial catalyst cost was not provided separately so estimated volume used by Andover unknown	13914	EPA cost manual shows catalyst volume is not a function of operating life, which is not valid. Estimated catalyst volumes were obtained by adjusting the Naughton 3 actual catalyst volumes for this unit. This value is only used to estimate catalyst replacement costs because vendor pricing already includes initial catalyst cost.	13914	EPA cost manual shows catalyst volume is not a function of operating life, which is not valid. Estimated catalyst volumes were obtained by adjusting the Naughton 3 actual catalyst volumes for this unit. This value is only used to estimate catalyst replacement costs because vendor pricing already includes initial catalyst cost.	Unknown	Initial catalyst cost was not provided separately so estimated volume used by Andover unknown	13914	EPA cost manual shows catalyst volume is not a function of operating life, which is not valid. Estimated catalyst volumes were obtained by adjusting the Naughton 3 actual catalyst volumes for this unit. This value is only used to estimate catalyst replacement costs because vendor pricing already includes initial catalyst cost.
56	where:												
57	NOx Efficiency Adjustment	1.06					Catalyst Cost in vendor estimate, this is not used.		Catalyst Cost in vendor estimate, this is not used.				Catalyst Cost in vendor estimate, this is not used.
58	NOx Adjustment Factor for inlet NOx	0.94					(see above)		(see above)				(see above)
59	Ammonia Slip Adjustment Factor	1.17					(see above)		(see above)				(see above)
60	Sulfur in Coal Adjustment Factor	1.02					(see above)		(see above)				(see above)
61	Temperature Adjustment Factor (for temps other than 700°F)	1.10					(see above)		(see above)				(see above)
62													
63	Catalyst Cross-Sectional Area	841					(see above)		(see above)				(see above)
64	SCR Reactor Cross-Sectional Area	967					(see above)		(see above)				(see above)
65	length	31					(see above)		(see above)				(see above)
66	width												
67	Estimate Number of Catalyst Layers	3	Estimated number of layers is too high. Bypass this value and use input values instead for further calculations of h(layer) and n(total)				Included in vendor estimate, this input is not used.		Included in vendor estimate, this input is not used.				Included in vendor estimate, this input is not used.
68	Height of Catalyst Layer	3.50					Included in vendor estimate, this input is not used.		Included in vendor estimate, this input is not used.				Included in vendor estimate, this input is not used.
69	Total Number of Catalyst Layers	4				4		4				4	
70	Height of SCR Reactor	51					Included in vendor estimate, this input is not used.		Included in vendor estimate, this input is not used.				Included in vendor estimate, this input is not used.

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Row	B: NAME OF VARIABLE	C: VARIABLE	D: UNITS	E: EQUATION NUMBER	F: EQUATION	G: EXAMPLE PROBLEM VERBATIM	I: S&L CORRECTED EPA EXAMPLE	J: Comment
71								
72	Ammonia Mass Flow Rate	$m_{reagent}$	lb/hr of NH_3	2.32	$m_{reagent} = \frac{NO_{x_{in}} \times Q_B \times NSR \times \eta_{NOx} \times M_{reagent}}{M_{NO_2} \times SR_F}$; $m_{reagent} = \frac{NOx \times Q \times .158 \times 17.03}{46.01}$	294	284	In the example problem (2.5 Example Problem) EPA does not use NOx efficiency in their calculation, yet the equation (2.32) on pg. 2-39 requires it.
73	Mass Flow Rate of Aqueous Reagent Solution	$m_{solution}$	lb/hr of NH3 solution	2.33	$m_{sol} = \frac{m_{reagent}}{C_{sol}}$	1,153	980	
74	Equivalent Dry Urea Consumption Rate		lb/hr		[illegible]			
75	Mass Flow Rate of Urea Solution	$m_{solution}$	lb/hr of NH3 solution	2.33	$m_{sol} = \frac{m_{reagent}}{C_{sol}}$			
76	Solution Volumetric Flow	q_{sol}	gph	2.34	$q_{sol} = \frac{m_{sol} \times 7.481}{71.1}$	154.00	131.00	
77	Storage Tank Volume	V_{tank}	gal	2.35	[illegible]	51,744	44,016	
78								
80	Direct Capital Cost	DC	$	2.36		$6,832,000	$6,799,443	
81	Adjustment for the SCR Reactor Height	$f(h_{SCR})$	$/MMBtu/hr	2.37	[illegible]	$149.00	$149.00	
82	Adjustment for the Ammonia Flow Rate	$f(NH_{3rate})$	$/MMBtu/hr	2.38	[illegible]	$90.00	$69.00	
83	Adjustment for Retrofit or New Boiler	f(new)	$/MMBtu/hr	2.39 + 2.40	Is it a retrofit or new boiler?	$0.00	$0.00	
84	Adjustment for SCR Bypass	f(bypass)	$/MMBtu/hr	2.41 + 2.42	Is a bypass installed?	$0.00	$0.00	
85	Capital Cost for the Initial Charge of Catalyst	$f(Vol_{catalyst})$	$/MMBtu/hr	2.43	$f(Vol_{catalyst}) = Vol_{catalyst} \times CC_{initial}$	$1,221,360	$1,221,360	
86	Indirect Installation Costs Due to General Facilities		$	Table 2.5	0.05xDC	$341,600	$339,972	
87	Indirect Installation Costs Due to Engineering and Home Office Fees		$	Table 2.6	0.10xDC	$683,200	$679,944	
88	Indirect Installation Costs Due to Process Contingency		$	Table 2.7	0.05xDC	$341,600	$339,972	
89	Total Indirect Installation Costs	IIC	$	Table 2.8	DCx(0.05+0.10+0.05)	$1,366,400	$1,359,889	
90	Project Contingency		$	Table 2.9	(DC+IIC)x0.15	$1,229,760	$1,223,900	
91	Total Plant Costs	PC	$	Table 2.10	DC+IIC+Project Contingency	$9,428,160	$9,383,231	
92	Allowance for Funds During Construction	AFUDC	$					
93	Preproduction Cost	PrePro	$	Table 2.11	0.02 x (PC+Construction)	$188,563	$187,665	
94	Inventory Capital	Inventory	$	Table 2.12	$m_{reagent}$ x days x 24 x inc	$39,128	$33,257	
95	Initial Catalyst and Chemicals		$					
96	**Total Capital Investment**	**TCI**	**$**	**Table 2.13**	**PC+Construction+PrePro+Inventory+Catalyst**	**$9,655,851**	**$9,604,153**	
97	Maintenance Cost		$/yr	2.46	$Annual\ Maintenance\ Cost = 0.015\ TCI$	$144,838	$144,062	
98	Power	P	kW	2.48		444	444	

Row	B: NAME OF VARIABLE	K: NAUGHTON 1 BASED ON CORRECTED EPA EXAMPLE WITH AMMONIA	L: Comment	M: NAUGHTON 1 BASED ON CORRECTED EPA EXAMPLE WITH UREA	N: Comment	O: NAUGHTON 1 BASED ON CORRECTED EPA EXAMPLE WITH ESCALATION AND WITH UREA	P: Comment	Q: NAUGHTON 1 BASED ON ANDOVER REPORT FEBRUARY 2013 (20-yr life / excluding AFUDC)	R: Comment
72	Ammonia Mass Flow Rate	127		127		127		109	Not in Andover report, but calculated from 100% Urea rate using 0.56 lb NH3 / lb of urea
73	Mass Flow Rate of Aqueous Reagent Solution	436			Not used as urea is the reagent				
74	Equivalent Dry Urea Consumption Rate			227	S&L added formulas and calculations to include U2A system. Value calculated for reagent costing.	227		195	
75	Mass Flow Rate of Urea Solution			453		453		390	
76	Solution Volumetric Flow	59.00		48.00	Volumetric flow rate of 50% urea solution with a density of 71.1 lb/ft3	48.00		41	
77	Storage Tank Volume	19,824		16,128		16,128			Tank volume included in Andover estimate unknown
80	Direct Capital Cost	$9,187,373		$9,187,373		$15,585,717	Since no adjustment factor exists for urea systems, S&L added the estimated capital cost for the urea system by scaling the Huntington estimate.	$33,928,100	As reported in Andover Report attachment.
81	Adjustment for the SCR Reactor Height	$124.00		$124.00		$124.00			Adjustment not used by Andover because EPA cost manual not followed
82	Adjustment for the Ammonia Flow Rate	-$17.00		-$17.00		-$17.00			Adjustment not used by Andover because EPA cost manual not followed
83	Adjustment for Retrofit or New Boiler	$0.00		$0.00		$0.00			Adjustment not used by Andover because EPA cost manual not followed
84	Adjustment for SCR Bypass	$0.00		$0.00		$0.00			Adjustment not used by Andover because EPA cost manual not followed
85	Capital Cost for the Initial Charge of Catalyst	$1,499,520		$1,499,520		$1,499,520			Adjustment not used by Andover because EPA cost manual not followed
86	Indirect Installation Costs Due to General Facilities	$459,369		$459,369		$779,286			Unknown because EPA cost manual not used
87	Indirect Installation Costs Due to Engineering and Home Office Fees	$918,737		$918,737		$1,558,572			Unknown because EPA cost manual not used
88	Indirect Installation Costs Due to Process Contingency	$459,369		$459,369		$779,286			Unknown because EPA cost manual not used
89	Total Indirect Installation Costs	$1,837,475		$1,837,475		$3,117,143		$10,178,430	As reported in Andover Report attachment.
90	Project Contingency	$1,653,727		$1,653,727		$2,805,429			Unknown because EPA cost manual not used
91	Total Plant Costs	$12,678,575		$12,678,575		$21,508,290		$44,106,530	
92	Allowance for Funds During Construction							$0	As reported in Andover Report attachment.
93	Preproduction Cost	$253,572		$253,572		$430,166			
94	Inventory Capital	$14,684		$15,232		$15,232			
95	Initial Catalyst and Chemicals								
96	**Total Capital Investment**	**$12,947,011**		**$12,947,379**		**$21,953,688**		**$44,106,530**	As reported in Andover Report attachment.
97	Maintenance Cost	$194,205		$194,211		$329,305		$363,200	Based on $2.27/kw-yr as reported in Andover Report attachment.
98	Power	586		666		756			

Row	B: NAME OF VARIABLE	S: NAUGHTON 1 BASED ON VENDOR BUDGETARY PRICING (20-yr life / excluding AFUDC)	T: Comment	U: NAUGHTON 1 BASED ON VENDOR BUDGETARY PRICING (20-yr life / including AFUDC)	V: Comment	W: NAUGHTON 1 BASED ON ANDOVER REPORT FEBRUARY 2013 (11-yr life / excluding AFUDC)	X: Comment	Y: NAUGHTON 1 BASED ON VENDOR BUDGETARY PRICING (11-yr life / excluding AFUDC)	Z: Comment
72	Ammonia Mass Flow Rate	107		107		109	Not in Andover report, but calculated from 100% Urea rate using 0.56 lb NH3 / lb of urea	107	
73	Mass Flow Rate of Aqueous Reagent Solution	107		107				107	
74	Equivalent Dry Urea Consumption Rate					195			
75	Mass Flow Rate of Urea Solution	0		0		390		0	
76	Solution Volumetric Flow	14.00		14.00		41		14.00	
77	Storage Tank Volume	4,704		4,704			Tank volume included in Andover estimate unknown	4,704	
80	Direct Capital Cost	$66,500,000	From Vendor Budgetary Pricing for EPC contract. Information provided includes only Total Direct Costs (per Item "A" from Table 2.5 in Cost Manual)	$66,500,000	From Vendor Budgetary Pricing for EPC contract. Information provided includes only Total Direct Costs (per Item "A" from Table 2.5 in Cost Manual)	$33,928,100	As reported in Andover Report attachment.	$66,500,000	From Vendor Budgetary Pricing for EPC contract. Information provided includes only Total Direct Costs (per Item "A" from Table 2.5 in Cost Manual)
81	Adjustment for the SCR Reactor Height		Covered in scaled estimate, this input is not used.		Covered in scaled estimate, this input is not used.		Adjustment not used by Andover because EPA cost manual not followed		Covered in scaled estimate, this input is not used.
82	Adjustment for the Ammonia Flow Rate		Covered in scaled estimate, this input is not used.		Covered in scaled estimate, this input is not used.		Adjustment not used by Andover because EPA cost manual not followed		Covered in scaled estimate, this input is not used.
83	Adjustment for Retrofit or New Boiler		Covered in scaled estimate, this input is not used.		Covered in scaled estimate, this input is not used.		Adjustment not used by Andover because EPA cost manual not followed		Covered in scaled estimate, this input is not used.
84	Adjustment for SCR Bypass		Covered in scaled estimate, this input is not used.		Covered in scaled estimate, this input is not used.		Adjustment not used by Andover because EPA cost manual not followed		Covered in scaled estimate, this input is not used.
85	Capital Cost for the Initial Charge of Catalyst		Covered in scaled estimate, this input is not used.		Covered in scaled estimate, this input is not used.		Adjustment not used by Andover because EPA cost manual not followed		Covered in scaled estimate, this input is not used.
86	Indirect Installation Costs Due to General Facilities	$3,325,000		$3,325,000			Unknown because EPA cost manual not used	$3,325,000	
87	Indirect Installation Costs Due to Engineering and Home Office Fees	$6,650,000		$6,650,000			Unknown because EPA cost manual not used	$6,650,000	
88	Indirect Installation Costs Due to Process Contingency	$3,325,000		$3,325,000			Unknown because EPA cost manual not used	$3,325,000	
89	Total Indirect Installation Costs	$13,300,000		$13,300,000		$10,178,430	As reported in Andover Report attachment.	$13,300,000	
90	Project Contingency	$11,970,000		$11,970,000			Unknown because EPA cost manual not used	$11,970,000	
91	Total Plant Costs	$91,770,000		$91,770,000		$44,106,530		$91,770,000	
92	Allowance for Funds During Construction	$8,774,000	Estimated by S&L using a 7% Cost of Capital for SCR and proposed Naughton 3 cash flows. <u>Note that this value is not included in the TCI, but is shown for information since this item does represent an actual cost to PacifiCorp.</u>	$8,774,000	Estimated by S&L using a 7% Cost of Capital for SCR and proposed Naughton 3 cash flows. <u>Included in the TCI as an actual cost to PacifiCorp for comparative purposes.</u>	$0	As reported in Andover Report attachment.	$8,774,000	Estimated by S&L using a 7% Cost of Capital for SCR and proposed Naughton 3 cash flows. <u>Note that this value is not included in the TCI, but is shown for information since this item does represent an actual cost to PacifiCorp.</u>
93	Preproduction Cost	$2,010,880		$2,010,880				$2,010,880	
94	Inventory Capital	$0	This item reflects urea only, which will not be part of capital costs. Other initial fills included in capital cost	$0	This item reflects urea only, which will not be part of capital costs. Other initial fills included in capital cost			$0	This item reflects urea only, which will not be part of capital costs. Other initial fills included in capital cost
95	Initial Catalyst and Chemicals	$35,000	Initial Catalyst Fills included as part of capital cost, therefore excluded in this item.	$35,000	Initial Catalyst Fills included as part of capital cost, therefore excluded in this item.			$35,000	Initial Catalyst Fills included as part of capital cost, therefore excluded in this item.
96	**Total Capital Investment**	**$93,815,880**		**$102,589,880**		**$44,106,530**	As reported in Andover Report attachment.	**$93,815,880**	
97	Maintenance Cost	$1,407,238		$1,538,848		$363,200	Based on $2.27/kw-yr as reported in Andover Report attachment.	$1,407,238	
98	Power	751		751				751	

	B	C	D	E	F	G	I	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y	Z
2	NAME OF VARIABLE	VARIABLE	UNITS	EQUATION NUMBER	EQUATION	EXAMPLE PROBLEM VERBATIM	S&L CORRECTED EPA EXAMPLE	Comment	NAUGHTON 1 BASED ON CORRECTED EPA EXAMPLE WITH AMMONIA	Comment	NAUGHTON 1 BASED ON CORRECTED EPA EXAMPLE WITH UREA	Comment	NAUGHTON 1 BASED ON CORRECTED EPA EXAMPLE WITH ESCALATION AND WITH UREA	Comment	NAUGHTON 1 BASED ON ANDOVER REPORT FEBRUARY 2013 (20-yr life / excluding AFUDC)	Comment	NAUGHTON 1 BASED ON VENDOR BUDGETARY PRICING (20-yr life / excluding AFUDC)	Comment	NAUGHTON 1 BASED ON VENDOR BUDGETARY PRICING (20-yr life / including AFUDC)	Comment	NAUGHTON 1 BASED ON ANDOVER REPORT FEBRUARY 2013 (11-yr life / excluding AFUDC)	Comment	NAUGHTON 1 BASED ON VENDOR BUDGETARY PRICING (11-yr life / excluding AFUDC)	Comment
99	Electricity Cost		$/yr	2.49	[illegible]	$52,538	$41,316		$262,548		$262,548	Increase in power consumption for U2A system is negligible, thus no adjustment needed	$298,123	Increased due to additional pressure drop associated with ductwork	$457,650	Based on $0.36/MW-hr as reported in Andover Report attachment	$177,593		$177,593		$457,650	Based on $0.36/MW-hr as reported in Andover Report attachment.	$177,593	
100	Reagent Solution Cost		$/yr	2.47	$ReagentCost = \dot{m}_{sol} \times 8760 \times CF_{total} \times Cost_{reagent}$	$275,435	$184,103		$348,772		$357,413		$357,413		$699,188	Based on $0.55/MW-hr as reported in Andover Report attachment.	$316,346		$316,346		$699,188	Based on $0.55/MW-hr as reported in Andover Report attachment.	$316,346	
101	Future Worth Factor	FWF		2.52	$FWF = i\left[\frac{1}{(1+i)^Y - 1}\right]$	0.14	0.14		0.31		0.23		0.23				0.23		0.23				0.23	
102	Years	Y	yr	2.53	$Y = \frac{h_{catalyst}}{CF_{total} \times 8760}$	6	6		3		4		4				4		4				4	
103	Factor for Catalyst Replacement	R_{layer}				3	3		3		3		3				3		3				3	
104	Annual Catalyst Replacement Cost		$/yr	2.50 + 2.51	$AnnualCatalystReplacementCost = FWF \times Vol_{catalyst} \times \frac{CC_{replace}}{R_{layer}}$	$68,871	$68,871		$187,232		$138,914		$138,914		$292,388	Based on $0.23/MW-hr as reported in Andover Report attachment.	$309,355	EPA formula excludes number of reactors. This formula has been updated to reflect catalyst in multiple reactors must be changed.	$309,355	EPA formula excludes number of reactors. This formula has been updated to reflect catalyst in multiple reactors must be changed.	$292,388	Based on $0.23/MW-hr as reported in Andover Report attachment.	$309,355	EPA formula excludes number of reactors. This formula has been updated to reflect catalyst in multiple reactors must be changed.
105	Annual Additional Water for Urea		$/yr		Volumetric flow rate of water, Dry Urea Consumption Rate * 1 lb H2O * 7.48 gal / (62.4 lb/ft3 * 1 lb urea)				$0		$1,071	Additional water would be needed for a U2A solid urea system in comparison with any other system because need the water to dissolve the solid urea. Value is based on gph flow rate of 50% urea solution. Naughton 3 had 0.006MMBtu/hr of steam guaranteed per pound of urea consumed.	$1,071		$0	Not included in Andover Report attachment.	$0		$0		$0	Not included in Andover Report attachment.	$0	
106	Annual Additional Steam for Urea Hydrolyzer		$/yr						$0		$53,612		$53,612		$7,628	Based on $0.006/MW-hr as reported in Andover Report attachment.	$0		$0		$7,628	Based on $0.006/MW-hr as reported in Andover Report attachment.	$0	
107	Total Variable Direct Cost				=Electricity Cost+Reagent Solution Cost + Annual Catalyst Replacement Cost + Water Cost	$396,843	$294,290		$798,552		$813,557		$849,133		$1,456,854		$803,293		$803,293		$1,456,854		$803,293	
108	Total Direct Annual Cost			2.45	=Maintenance Cost +Total Variable Direct Cost	$541,681	$438,352		$992,757		$1,007,768		$1,178,438		$1,820,054		$3,148,690	+ Property Tax Factor PacifiCorp is subject to property taxes. per EPA cost manual 0.01*TCI was used	$3,368,040	+ Property Tax Factor PacifiCorp is subject to property taxes, per EPA cost manual 0.01*TCI was used	$1,820,054		$3,148,690	+ Property Tax Factor PacifiCorp is subject to property taxes per EPA cost manual 0.01*TCI was used.
109	Property Tax Factor	F(tax)		2.5.5.8		0.00	0.00		0.00		0.00		0.00				$938,159		$1,025,899				$938,159	
110	Overhead Factor	F(ovhd)				0.00	0.00		0.00		0.00		0.00				0.00		0.00				0.00	
111	Capital Recovery Factor	CRF		2.55	$CRF = \frac{i(1+i)^n}{(1+i)^n - 1}$	0.0944	0.0944		0.0944		0.0944		0.0944		0.1064	Based on a capital recovery factor of 9.44% and a property taxes and insurance rate of 1.20%, Total Charge Rate = 10.64%.	0.0944		0.0944		0.1454	Based on a capital recovery factor of 9.44% and a property taxes and insurance rate of 1.20%. Total Charge Rate = 10.64%.	0.1334	
112	Indirect Annual Costs	IDAC	$/yr	2.54	$IDAC = CRF \times TCI$	$911,444	$906,564		$1,222,106		$1,222,141		$2,072,273		$4,692,935		$8,855,556		$9,683,759		$6,413,089		$12,510,995	
113	Total Annual Cost	TAC	$/yr	2.56	[illegible]	**$1,453,125**	**$1,344,916**		**$2,214,863**		**$2,229,909**		**$3,250,711**		**$6,504,603**	As reported in Andover Report attachment.	**$12,004,246**		**$13,051,799**		**$8,233,143**	As reported in Andover Report attachment	**$15,659,686**	
114	Annual NOx Removed		tons/yr	2.57	NOx Removed	864	680		1,286		1,286		1,286		1,109	As reported in Andover Report attachment.	1,109	Aligned with Andover Report assumption for cost-effectiveness comparison.	1,109	Aligned with Andover Report assumption for cost-effectiveness comparison.	1,109	As reported in Andover Report attachment.	1,109	Aligned with Andover Report assumption for cost-effectiveness comparison.
115	Cost Effectiveness		$/ton	2.58	$Cost\ Effectiveness = \frac{TAC}{NO_x\ Removed/year}$	**$1,681**	**$1,978**		**$1,722**		**$1,734**		**$2,527**		**$5,867**	**As reported in Andover Report attachment.**	**$10,824**		**$11,769**		**$7,424**	**As reported in Andover Report attachment.**	**$14,121**	
116	**Note 1 - In attachment EPA-R08-OAR-2012-0026-0087, Andover calculates SCR cost effectiveness in two ways: a) starting from baseline emissions of 0.21, assuming combustion controls already in place (see worksheet "NOx - SCR_01_03")and b) starting from baseline emissions of 0.52, assuming combustion controls are not in place (see worksheet "Naughton"). This worksheet reports Andover's results assuming combustion controls are already in place since this is consistent with current operation at Naughton**																							

Naughton Unit 2

	B	C	D	E	F	G	I	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y	Z
2	NAME OF VARIABLE	VARIABLE	UNITS	EQUATION NUMBER	EQUATION	EXAMPLE PROBLEM VERBATIM	S&L CORRECTED EPA EXAMPLE	Comment	NAUGHTON 2 BASED ON CORRECTED EPA EXAMPLE WITH AMMONIA	Comment	NAUGHTON 2 BASED ON CORRECTED EPA EXAMPLE WITH UREA	Comment	NAUGHTON 2 BASED ON CORRECTED EPA EXAMPLE WITH ESCALATION AND WITH UREA	Comment	NAUGHTON 2 BASED ON ANDOVER REPORT FEBRUARY 2013 (20-yr life / excludes AFUDC)	Comment	NAUGHTON 2 BASED ON VENDOR BUDGETARY PRICING (20-yr life / excludes AFUDC)	Comment	NAUGHTON 2 BASED ON VENDOR BUDGETARY PRICING (20-yr life / includes AFUDC)	Comment	NAUGHTON 2 BASED ON ANDOVER REPORT FEBRUARY 2013 (11-yr life / excludes AFUDC)	Comment	NAUGHTON 2 BASED ON VENDOR BUDGETARY PRICING (11-yr life / excludes AFUDC)	Comment
3																								
4	Fuel High Heating Value	HHV	Btu/lb	-		10,000	10,000		10,000	Based on typical Naughton coal	10,000		10,000											
5	Maximum Fuel Consumption Rate	$\dot{m}_{fuel}$	lb/hr	-	$\dot{m}_{fuel} = \frac{Q_B}{HHV} \times 10^6$	100,000	100,000		234,900	Calculated from maximum heat input and fuel high heating value	234,900		234,900											
7	Max Generating Capacity		MW		$m_{fuel} = \frac{AnnualHeat\ Input}{HHV} \times 10^6$				220	Provided by PC	220		220		210	As reported in Andover Report attachment, net reliable	220		220		210	As reported in Andover Report attachment, net reliable	220	
10	Average Number of Plant Operating Hours per Year		hr						7884	Estimated to achieve 90% capacity factor in Row 12	7884		7884				7884		7884				7884	
11	Number of SCR Operating Days	t(scr)	days	-		155	155		365	SCR operated year round	365		365				365		365				365	
12	Plant Capacity Factor	CF_{plant}		-		50%	50%		90%	Operating hours divided by 8760	-		-		-		-		-		-		-	
13	Uncontrolled NOx Concentration	NOx_{in}	lbNO2/MMBtu	-		0.86	0.86		0.26		0.26		0.26		0.21	As reported in Andover Report attachment. (See Note 1)	0.21	Aligned with Andover Report assumption for cost-effectiveness comparison.	0.21	Aligned with Andover Report assumption for cost-effectiveness comparison.	0.21	As reported in Andover Report attachment. (See Note 1)	0.21	Aligned with Andover Report assumption for cost-effectiveness comparison.
14	NOx Concentration used for Reagent Consumption	NOx_{in}	lbNO2/MMBtu	-		0.86	0.86		0.26		0.26		0.26		0.21	As reported in Andover Report attachment. (See Note 1)	0.21	Aligned with Andover Report assumption for reagent cost comparison.	0.21	Aligned with Andover Report assumption for reagent cost comparison.	0.21	As reported in Andover Report attachment. (See Note 1)	0.21	Aligned with Andover Report assumption for reagent cost comparison
15	Required Controlled NOx Concentration	NOx_{out}	lbNO2/MMBtu	-		0.13	0.13		0.07		0.07		0.07		0.05	Based on 76.3% Removal used in Andover Report attachment.	0.05	Aligned with Andover Report assumption for comparison purposes.	0.05	Aligned with Andover Report assumption for comparison purposes.	0.05	Based on 76.3% Removal used in Andover Report attachment	0.05	Aligned with Andover Report assumption for comparison purposes.
16	Acceptable Ammonia Slip	Slip	ppm	-		2.00	2.00		2.00		2.00		2.00				2.00		2.00				2.00	
17	Coal Type			-		Eastern Bituminous	Eastern Bituminous		Bituminous		Bituminous		Bituminous		PRB	As reported in Andover Report attachment.	Bituminous	Fuel at Naughton is actually Western Sub-bituminous, but this category not in Table 2.4	Bituminous	Fuel at Naughton is actually Western Sub-bituminous, but this category not in Table 2.4	PRB	As reported in Andover Report attachment.	Bituminous	Fuel at Naughton is actually Western Sub-bituminous, but this category not in Table 2.4
18	Fuel Volumetric Flow Rate	q_{fuel}	ft³/min-MMBtu/hr	-		484.00	484.00		484.00		484.00		484.00					Not used, Vendor performed combustion calculation to arrive at volume		Not used, Vendor performed combustion calculation to arrive at volume				Not used, Vendor performed combustion calculation to arrive at volume
19	Fuel Heating Value		Btu/lb	-		12696.00	12696.00		-		-		-				-		-				-	
20	Sulfur Content of Fuel	S	wt%	-		1.0	1.0		1.2		1.2		1.2				1.2		1.2				1.2	
21	Fuel Ash Content	A	wt%	-		7.7%	7.7%		-		-		-				-		-				-	
22	Actual Stoichiometric Ratio	ASR		-		1.05	1.05		1.05		1.05		1.05				1.05		1.05				1.05	
23	Concentration of Reagent	C_{sol}	%	-		29%	29%		29%		50%	To account for a U2A system	50%		50%	As reported in Andover Report attachment.	100%		100%		50%	As reported in Andover Report attachment.	100%	
24	Days of Storage of Reagent	t	days	-		14.00	14.00		14.00		14.00		14.00				14.00		14.00				14.00	
25	Pressure Drop for SCR Ductwork	ΔP_{duct}	in. w.g.	-		3.00	3.00		3.00		3.00		4.00	More Typical for SCR systems			4.00		4.00				4.00	
26	Pressure Drop for each Catalyst Layer	$\Delta P_{catalyst}$	in. w.g.	-		1.00	1.00		1.00		1.00		1.00				1.00		1.00				1.00	
27	Number of SCR Reactors	N(scr)				1.00	1.00		1.00		1.00		1.00				1.00		1.00				1.00	
28	Temperature at Reactor Inlet	T	°F	-		650.00	650.00		665.00		665.00		665.00				763.00		763.00				763.00	
29																								
30	Cost Year			-		Dec-98	Dec-98		Dec-98		Dec-98		Dec-98	Year the Cost is Incurred										
31	Equipment Life	n	yr	-		20.00	20.00		20.00		20.00		20.00				20.00		20.00		11.00		11.00	
32	Annual Interest Rate	i		-		7%	7%		7%		7%		7%				7%		7%				7%	
33	Chemical Engineering Plant Cost Index Value 1998												389.50	Chemical Engineering Magazine Plant Cost Index value from 1998										
34	Chemical Engineering Plant Cost Index Value 2011												600.60	Chemical Engineering Magazine Plant Cost Index value from 2011										
35	Catalyst Cost, Initial	$CC_{initial}$	$/ft³	-		$240.00	$240.00		$240.00		$240.00		$240.00					Included in Vendor Budgetary Pricing		Included in Vendor Budgetary Pricing				Included in Vendor Budgetary Pricing
36	Catalyst Cost, Replacement	$CC_{replace}$	$/ft³	-	$CC_{replace} = CC_{initial}(1.065)$	$290.00	$290.00		$290.00		$290.00		$290.00		$155.74	Based on 5500 m3 used in Andover Report attachment	$290.00		$290.00		$155.74	Based on 5500 m3 used in Andover Report attachment	$290.00	
37	Electrical Power Cost	$Cost_{elect}$	$/kWh	-		0.05	0.05		0.05		0.05		0.05		0.06	As reported in Andover Report attachment	0.03	Price Provided by PC	0.03	Price Provided by PC	0.06	As reported in Andover Report attachment	0.03	Price Provided by PC
38	Reagent Cost	$Cost_{reagent}$	$/lb	-	lrc	0.101	0.101		0.101		0.200	Cost of Reagent adjusted to pricing for $/lb of Dry Urea	0.200		0.225	Based on 450 per ton used in Andover Report attachment	0.375	Price Provided by PC from DASCO quote July 2012	0.375	Price Provided by PC from DASCO quote July 2012	0.225	Based on 450 per ton used in Andover Report attachment	0.375	Price Provided by PC from DASCO quote July 2012
39	Operating Life of Catalyst	$h_{catalyst}$	hr	-		24,000	24,000		24,000		32,000	Based on PC target of 4-year operation cycle	32,000				32,000		32,000				32,000	
40	Catalyst Layers Full	R_{layer}	#	-		2	2		3		3		3				3		3				3	
41	Catalyst Layers Empty	R_{empty}	#	-		1	1		1	Empty layer for addition of extra catalyst layer in future to boost performance	1		1				1		1				1	
42	Cost of Water		$/1000-gal								5	Price of water per 1000 gallons	5				5		5				5	
43																								

Row	B: NAME OF VARIABLE	C: VARIABLE	D: UNITS	E: EQUATION NUMBER	F: EQUATION	G: EXAMPLE PROBLEM VERBATIM	I: S&L CORRECTED EPA EXAMPLE	J: Comment	K: NAUGHTON 2 BASED ON CORRECTED EPA EXAMPLE WITH AMMONIA	L: Comment
44										
47	Max Heat Input Rate	Q_B	MMBtu/hr	2.3	$Q_B = \frac{HV \times \dot{m}_{fuel}}{10^6}$	1,000	1,000		2,349	Provided by PC
48	Plant Capacity Factor	CF_{plant}		2.7	$CF_{plant} = \frac{actual\ \dot{m}_{fuel}}{\dot{m}_{fuel} \times 8760}$	50%	50%		90%	90% from Permit Calculation
49	SCR Capacity Factor	CF_{SCR}		2.8	[illegible]	42%	42%		100%	
50	Total Capacity Factor	CF_{total}		2.6	$CF_{total} = CF_{plant} \times CF_{SCR}$	27%	21%	Fixed EPA calculation error	90%	
51	Flue Gas Volumetric Flow Rate at Inlet/Reactor	$q_{flue\,gas}$	acfm	2.12	[illegible]	463,138	463,138		1,102,613	
52	NOx Removal Efficient for Cost-Effectiveness					0.85	0.85		0.73	
53	NOx Removal Efficiency for Reagent Consumption	η_{NOx}		2.9	$\eta_{NOx} = \frac{NO_{x_{in}} - NO_{x_{out}}}{NO_{x_{in}}}$	0.85	0.85		0.73	
54										
55	Catalyst Volume/Reactor	$Vol_{catalyst}$	ft³	2.19	$Vol_{catalyst} = 2.81 \times Q_B \times \eta_{adj} \times Slip_{adj} \times NO_{x_{adj}} \times S_{adj} \times \frac{T_{adj}}{N_{SCR}}$	5089	5089		8538	
56	where:	-	-	-						
57	NOx Efficiency Adjustment	η_{adj}		2.20	[illegible]	1.19	1.19		1.06	
58	NOx Adjustment Factor for inlet NOx	NOx_{adj}		2.21	[illegible]	1.13	1.13		0.94	
59	Ammonia Slip Adjustment Factor	$Slip_{adj}$		2.22	[illegible]	1.17	1.17		1.17	
60	Sulfur in Coal Adjustment Factor	S_{adj}		2.23	[illegible]	1.01	1.01		1.02	
61	Temperature Adjustment Factor (for temps other than 700°F)	T_{adj}	°F	2.24	[illegible]	1.15	1.15		1.10	
62										
63	Catalyst Cross-Sectional Area	$A_{catalyst}$	ft²	2.25	[illegible]	482	482		1149	
64	SCR Reactor Cross-Sectional Area	A_{SCR}	ft²	2.26	$A_{SCR} = 1.15 \times A_{catalyst}$	554	554		1321	
65	length	l	ft	2.27	$l = w = (A_{SCR})^{1/2}$	23.50	23.50		36	
66	width	w								
67	Estimate Number of Catalyst Layers	n_{layer}		2.28	$n_{layer} = \frac{Vol_{catalyst}}{3.1 \times A_{catalyst}}$	3	3	Estimated number of layers is less than input. Bypass this value and use input values instead for further calculations of h(layer) and n(total)	3	Estimated number of layers is too high. Bypass this value and use input values instead for further calculations of h(layer) and n(total)
68	Height of Catalyst Layer	h_{layer}	ft	2.29		4.50	4.50		3.50	
69	Total Number of Catalyst Layers	n_{total}	#	2.30	$n_{total} = n_{layer} + n_{empty}$	4	4		4	
70	Height of SCR Reactor	h_{SCR}	ft	2.31	[illegible]	55	55		51	

Row	B: NAME OF VARIABLE	M: NAUGHTON 2 BASED ON CORRECTED EPA EXAMPLE WITH UREA	N: Comment	O: NAUGHTON 2 BASED ON CORRECTED EPA EXAMPLE WITH ESCALATION AND WITH UREA	P: Comment	Q: NAUGHTON 2 BASED ON ANDOVER REPORT FEBRUARY 2013 (20-yr life / excludes AFUDC)	R: Comment	S: NAUGHTON 2 BASED ON VENDOR BUDGETARY PRICING (20-yr life / excludes AFUDC)
44								
47	Max Heat Input Rate	2,349		2,349		2,250	As reported in Andover Report attachment.	2,349
48	Plant Capacity Factor	90%		90%		84.4%	As reported in Andover Report attachment.	90%
49	SCR Capacity Factor	100%		100%				100%
50	Total Capacity Factor	90%		90%				90%
51	Flue Gas Volumetric Flow Rate at Inlet/Reactor	1,102,613		1,102,613				1,522,000
52	NOx Removal Efficient for Cost-Effectiveness	0.73		0.73				0.76
53	NOx Removal Efficiency for Reagent Consumption	0.73		0.73				0.76
54								
55	Catalyst Volume/Reactor	8538		8538		Unknown	Initial catalyst cost was not provided separately so estimated volume used by Andover unknown	21083
56	where:							
57	NOx Efficiency Adjustment	1.06		1.06				
58	NOx Adjustment Factor for inlet NOx	0.94		0.94				
59	Ammonia Slip Adjustment Factor	1.17		1.17				
60	Sulfur in Coal Adjustment Factor	1.02		1.02				
61	Temperature Adjustment Factor (for temps other than 700°F)	1.10		1.10				
62								
63	Catalyst Cross-Sectional Area	1149		1149				
64	SCR Reactor Cross-Sectional Area	1321		1321				
65	length	36		36				
66	width							
67	Estimate Number of Catalyst Layers	3	Estimated number of layers is too low. Bypass this value and use input values instead for further calculations of h(layer) and n(total)	3	Estimated number of layers is too high. Bypass this value and use input values instead for further calculations of h(layer) and n(total)			
68	Height of Catalyst Layer	3.50		3.50				
69	Total Number of Catalyst Layers	4		4				4
70	Height of SCR Reactor	51		51				

Row	B: NAME OF VARIABLE	T: Comment	U: NAUGHTON 2 BASED ON VENDOR BUDGETARY PRICING (20-yr life / includes AFUDC)	V: Comment	W: NAUGHTON 2 BASED ON ANDOVER REPORT FEBRUARY 2013 (11-yr life / excludes AFUDC)	X: Comment	Y: NAUGHTON 2 BASED ON VENDOR BUDGETARY PRICING (11-yr life / excludes AFUDC)	Z: Comment
44								
47	Max Heat Input Rate		2,349		2,250	As reported in Andover Report attachment.	2,349	
48	Plant Capacity Factor		90%		84.4%	As reported in Andover Report attachment.	90%	
49	SCR Capacity Factor		100%				100%	
50	Total Capacity Factor		90%				90%	
51	Flue Gas Volumetric Flow Rate at Inlet/Reactor	Per Vendor's Combustion Calculation	1,522,000	Per Vendor's Combustion Calculation			1,522,000	Per Vendor's Combustion Calculation
52	NOx Removal Efficient for Cost-Effectiveness		0.76				0.76	
53	NOx Removal Efficiency for Reagent Consumption		0.76				0.76	
54								
55	Catalyst Volume/Reactor	EPA cost manual shows catalyst volume is not a function of operating life, which is not valid. Estimated catalyst volumes were obtained by adjusting the Naughton 3 actual catalyst volumes for this unit. <u>This value is only used to estimate catalyst replacement costs because vendor pricing already includes initial catalyst cost.</u>	21083	EPA cost manual shows catalyst volume is not a function of operating life, which is not valid. Estimated catalyst volumes were obtained by adjusting the Naughton 3 actual catalyst volumes for this unit. <u>This value is only used to estimate catalyst replacement costs because vendor pricing already includes initial catalyst cost.</u>	Unknown	Initial catalyst cost was not provided separately so estimated volume used by Andover unknown	21083	EPA cost manual shows catalyst volume is not a function of operating life, which is not valid. Estimated catalyst volumes were obtained by adjusting the Naughton 3 actual catalyst volumes for this unit. <u>This value is only used to estimate catalyst replacement costs because vendor pricing already includes initial catalyst cost.</u>
56	where:							
57	NOx Efficiency Adjustment	Catalyst Cost in vendor estimate, this is not used.		Catalyst Cost in vendor estimate, this is not used.				Catalyst Cost in vendor estimate, this is not used.
58	NOx Adjustment Factor for inlet NOx	(see above)		(see above)				(see above)
59	Ammonia Slip Adjustment Factor	(see above)		(see above)				(see above)
60	Sulfur in Coal Adjustment Factor	(see above)		(see above)				(see above)
61	Temperature Adjustment Factor (for temps other than 700°F)	(see above)		(see above)				(see above)
62								
63	Catalyst Cross-Sectional Area	(see above)		(see above)				(see above)
64	SCR Reactor Cross-Sectional Area	(see above)		(see above)				(see above)
65	length	(see above)		(see above)				(see above)
66	width							
67	Estimate Number of Catalyst Layers	Included in vendor estimate, this input is not used.		Included in vendor estimate, this input is not used.				Included in vendor estimate, this input is not used.
68	Height of Catalyst Layer	Included in vendor estimate, this input is not used.		Included in vendor estimate, this input is not used.				Included in vendor estimate, this input is not used.
69	Total Number of Catalyst Layers		4				4	
70	Height of SCR Reactor	Included in vendor estimate, this input is not used.		Included in vendor estimate, this input is not used.				Included in vendor estimate, this input is not used.

	B	C	D	E	F	G	I	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y	Z
2	NAME OF VARIABLE	VARIABLE	UNITS	EQUATION NUMBER	EQUATION	EXAMPLE PROBLEM VERBATIM	S&L CORRECTED EPA EXAMPLE	Comment	NAUGHTON 2 BASED ON CORRECTED EPA EXAMPLE WITH AMMONIA	Comment	NAUGHTON 2 BASED ON CORRECTED EPA EXAMPLE WITH UREA	Comment	NAUGHTON 2 BASED ON CORRECTED EPA EXAMPLE WITH ESCALATION AND WITH UREA	Comment	NAUGHTON 2 BASED ON ANDOVER REPORT FEBRUARY 2013 (20-yr life / excludes AFUDC)	Comment	NAUGHTON 2 BASED ON VENDOR BUDGETARY PRICING (20-yr life / excludes AFUDC)	Comment	NAUGHTON 2 BASED ON VENDOR BUDGETARY PRICING (20-yr life / includes AFUDC)	Comment	NAUGHTON 2 BASED ON ANDOVER REPORT FEBRUARY 2013 (11-yr life / excludes AFUDC)	Comment	NAUGHTON 2 BASED ON VENDOR BUDGETARY PRICING (11-yr life / excludes AFUDC)	Comment
71																								
72	Ammonia Mass Flow Rate	$m_{reagent}$	lb/hr of NH_3	2.32	$m_{reagent} = \frac{NOx_i \times Q_B \times ASR \times 17.03}{46.01}$	334	284	in the example problem (2.5 Example Problem). EPA does not use NOx efficiency in their calculation, yet the equation (2.32) on pg 2-39 requires it	173		173		173		142	Not in Andover report, but calculated from 100% Urea rate using 0.56 lb NH3 / lb of urea	146		146		142	Not in Andover report, but calculated from 100% Urea rate using 0.56 lb NH3 / lb of urea	145	
73	Mass Flow Rate of Aqueous Reagent Solution	$m_{solution}$	lb/hr of NH3 solution	2.33		1,153	980		598			Not used as urea is the reagent					146		146				146	
74	Equivalent Dry Urea Consumption Rate		lb/hr		$m_{urea} = \frac{m_{sol}}{0.56}$						310	S&L added formulas and calculations to include U2A system. Value calculated for reagent costing	310		253						253			
75	Mass Flow Rate of Urea Solution	$m_{solution}$	lb/hr of NH3 solution	2.33							619		619		506						506			
76	Solution Volumetric Flow	q_{sol}	gph	2.34	$q_{sol} = \frac{m_{sol} \times 7.481}{71.1}$	154.00	131.00		80.00		65.00	Volumetric flow rate of 50% urea solution with a density of 71.1 lb/ft3	65.00		53		20.00		20.00		53		20.00	
77	Storage Tank Volume	V_{tank}	gal	2.35		51,744	44,016		26,880		21,840		21,840			Tank volume included in Andover estimate unknown.	6,720		6,720			Tank volume included in Andover estimate unknown.	6,720	
78																								
80	Direct Capital Cost	DC	$	2.36		$6,832,000	$6,799,443		$11,466,926		$11,466,926		$19,392,734	Since no adjustment factor exists for urea systems, S&L added the estimated capital cost for the urea system by scaling the Huntington estimate.	$42,037,165	As reported in Andover Report attachment.	$66,100,000	From Vendor Budgetary Pricing for EPC contract. Information provided includes only Total Direct Costs (per item "A" from Table 2.5 in Cost Manual)	$66,100,000	From Vendor Budgetary Pricing for EPC contract. Information provided includes only Total Direct Costs (per item "A" from Table 2.5 in Cost Manual)	$42,037,165	As reported in Andover Report attachment.	$66,100,000	From Vendor Budgetary Pricing for EPC contract. Information provided includes only Total Direct Costs (per item "A" from Table 2.5 in Cost Manual)
81	Adjustment for the SCR Reactor Height	$f(h_{SCR})$	$/MMBtu/hr	2.37		49.00	$149.00		$124.00		$124.00		$124.00			Adjustment not used by Andover because EPA cost manual not followed		Included in vendor estimate, this input is not used.		Included in vendor estimate, this input is not used.		Adjustment not used by Andover because EPA cost manual not followed		Included in vendor estimate, this input is not used.
82	Adjustment for the Ammonia Flow Rate	$f(NH_{3rate})$	$/MMBtu/hr	2.38		$90.00	$69.00		-$17.00		-$17.00		-$17.00			Adjustment not used by Andover because EPA cost manual not followed		Included in vendor estimate, this input is not used		Included in vendor estimate, this input is not used		Adjustment not used by Andover because EPA cost manual not followed		Included in vendor estimate, this input is not used.
83	Adjustment for Retrofit or New Boiler	f(new)	$/MMBtu/hr	2.39 + 2.40	Is it a retrofit or new boiler?	$0.00	$0.00		$0.00		$0.00		$0.00			Adjustment not used by Andover because EPA cost manual not followed		Included in vendor estimate, this input is not used.		Included in vendor estimate this input is not used.		Adjustment not used by Andover because EPA cost manual not followed		Included in vendor estimate, this input is not used.
84	Adjustment for SCR Bypass	f(bypass)	$/MMBtu/hr	2.41 + 2.42	Is a bypass installed?	$0.00	$0.00		$0.00		$0.00		$0.00			Adjustment not used by Andover because EPA cost manual not followed		Included in vendor estimate, this input is not used.		Included in vendor estimate, this input is not used.		Adjustment not used by Andover because EPA cost manual not followed		Included in vendor estimate, this input is not used.
85	Capital Cost for the Initial Charge of Catalyst	$f(Vol_{catalyst})$	$/MMBtu/hr	2.43	$f(Vol_{catalyst}) = Vol_{catalyst} \cdot CC_{initial}$	$1,221,360	$1,221,360		$2,049,120		$2,049,120		$2,049,120			Adjustment not used by Andover because EPA cost manual not followed		Included in vendor estimate, this input is not used		Included in vendor estimate, this input is not used.		Adjustment not used by Andover because EPA cost manual not followed		Included in vendor estimate, this input is not used.
86	Indirect Installation Costs Due to General Facilities		$	Table 2.5	0.05xDC	$341,600	$339,972		$573,346		$573,346		$969,637			Unknown because EPA cost manual not used	$3,305,000		$3,305,000			Unknown because EPA cost manual not used	$3,305,000	
87	Indirect Installation Costs Due to Engineering and Home Office Fees		$	Table 2.5	0.10xDC	$683,200	$679,944		$1,146,693		$1,146,693		$1,939,273			Unknown because EPA cost manual not used	$6,610,000		$6,610,000			Unknown because EPA cost manual not used	$6,610,000	
88	Indirect Installation Costs Due to Process Contingency		$	Table 2.5	0.05xDC	$341,600	$339,972		$573,346		$573,346		$969,637			Unknown because EPA cost manual not used	$3,305,000		$3,305,000			Unknown because EPA cost manual not used	$3,305,000	
89	Total Indirect Installation Costs	IIC	$	Table 2.5	DCx(0.05+0.10+0.05)	$1,366,400	$1,359,889		$2,293,385		$2,293,385		$3,878,547		$12,611,149	As reported in Andover Report attachment.	$13,220,000		$13,220,000		$12,611,149	As reported in Andover Report attachment.	$13,220,000	
90	Project Contingency		$	Table 2.5	(DC+IIC)x0.15	$1,229,760	$1,223,900		$2,064,047		$2,064,047		$3,490,692			Unknown because EPA cost manual not used	$11,898,000		$11,898,000			Unknown because EPA cost manual not used	$11,898,000	
91	Total Plant Costs	PC	$	Table 2.5	DC+IIC+Project Contingency	$9,428,160	$9,383,231		$15,824,357		$15,824,357		$26,761,973		$54,648,314		$91,218,000		$91,218,000		$54,648,314		$91,218,000	
92	Allowance for Funds During Construction	AFUDC	$												$0	As reported in Andover Report attachment	$8,725,000	Estimated by S&L using a 7% Cost of Capital for SCR and proposed Naughton 3 cash flows. Note that this value is not included in the TCI but is shown for information since this item does represent an actual cost to PacifiCorp.	$8,725,000	Estimated by S&L using a 7% Cost of Capital for SCR and proposed Naughton 3 cash flows. Included in the TCI as an actual cost to PacifiCorp for comparative purposes.	$0	As reported in Andover Report attachment	$8,725,000	Estimated by S&L using a 7% Cost of Capital for SCR and proposed Naughton 3 cash flows. Note that this value is not included in the TCI but is shown for information since this item does represent an actual cost to PacifiCorp.
93	Preproduction Cost	PrePro	$	Table 2.5	0.02 x (PC+Construction)	$188,563	$187,665		$316,487		$316,487		$535,239				$1,998,860		$1,998,860				$1,998,860	
94	Inventory Capital	Inventory	$	Table 2.5	m_{sol} x days×24x inc	$39,128	$33,257		$20,294		$20,815		$20,815				$0	This item reflects urea only, which is not be part of vendor pricing. Initial Catalyst Fills included as part of vendor pricing therefore excluded in this item.	$0	This item reflects urea only, which is not be part of vendor pricing. Initial Catalyst Fills included as part of vendor pricing therefore excluded in this item.			$0	This item reflects urea only, which is not be part of vendor pricing. Initial Catalyst Fills included as part of vendor pricing therefore excluded in this item.
95	Initial Catalyst and Chemicals		$														$35,000		$35,000				$35,000	
96	Total Capital Investment	TCI	$	Table 2.5	PC+Construction+PrePro+Inventory+Catalyst	$9,655,851	$9,604,153		$16,161,138		$16,161,659		$27,318,028		$54,648,314	As reported in Andover Report attachment	$93,251,860		$101,976,860		$54,648,314	As reported in Andover Report attachment	$93,251,860	
97	Maintenance Cost		$/yr	2.46	$Annual\ Maintenance\ Cost = 0.015 \times TCI$	$144,838	$144,062		$242,417		$242,425		$409,770		$563,300	Based on $1.73/kw-yr as reported in Andover Report attachment	$1,398,778		$1,529,653		$303,300	Based on $1.73/kw-yr as reported in Andover Report attachment	$1,398,778	
98	Power	P	kW	2.48		444	444		910		910		1,035				1,026		1,026				1,026	

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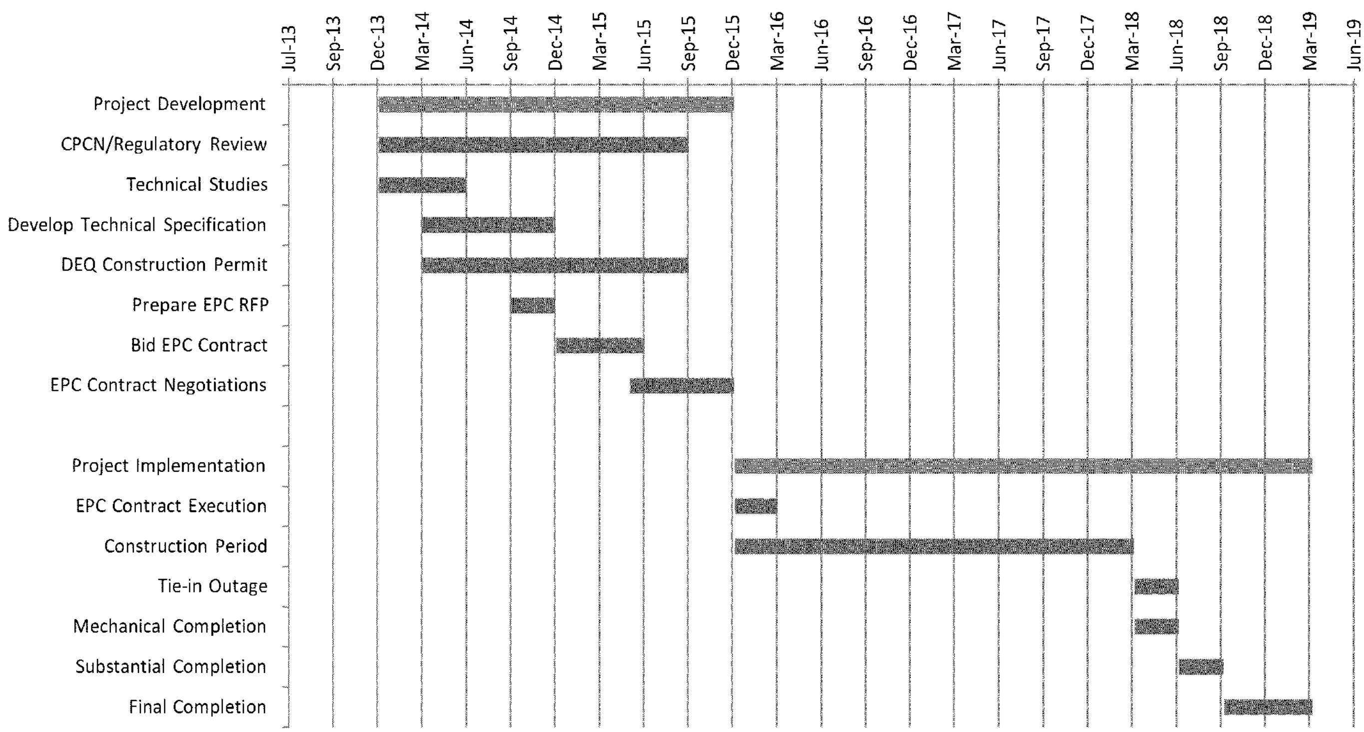
	B	C	D	E	F	G	I	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y	Z
2	NAME OF VARIABLE	VARIABLE	UNITS	EQUATION NUMBER	EQUATION	EXAMPLE PROBLEM VERBATIM	S&L CORRECTED EPA EXAMPLE	Comment	NAUGHTON 2 BASED ON CORRECTED EPA EXAMPLE WITH AMMONIA	Comment	NAUGHTON 2 BASED ON CORRECTED EPA EXAMPLE WITH UREA	Comment	NAUGHTON 2 BASED ON CORRECTED EPA EXAMPLE WITH ESCALATION AND WITH UREA	Comment	NAUGHTON 2 BASED ON ANDOVER REPORT FEBRUARY 2013 (20-yr life / excludes AFUDC)	Comment	NAUGHTON 2 BASED ON VENDOR BUDGETARY PRICING (20-yr life / excludes AFUDC)	Comment	NAUGHTON 2 BASED ON VENDOR BUDGETARY PRICING (20-yr life / includes AFUDC)	Comment	NAUGHTON 2 BASED ON ANDOVER REPORT FEBRUARY 2013 (11-yr life / excludes AFUDC)	Comment	NAUGHTON 2 BASED ON VENDOR BUDGETARY PRICING (11-yr life / excludes AFUDC)	Comment
99	Electricity Cost		$/yr	2.49	[illegible] $Annual\ Electricity\ Cost = Power \times Cost_{elect} \times t_{op}$	$52,538	$41,316		$358,769		$358,769	Increase in power consumption for U2A system is negigible, thus no adjustment needed	$407,383	Increased due to additional pressure drop associated with ductwork	$0	Based on $0.35/MW-hr as reported in Andover Report attachment.	$242,680		$242,680		$0	Based on $0.35/MW-hr as reported in Andover Report attachment.	$242,680	
100	Reagent Solution Cost		$/yr	2.47	$Reagent\ Cost = \frac{q_{sol}}{m_{sol}} \times 8760 \times CF_{total} \times Cost_{reagent}$	$275,435	$184,103		$476,178		$488,401		$488,401		$838,416	Based on $0.54/MW-hr as reported in Andover Report attachment.	$431,850		$431,850		$838,416	Based on $0.54/MW-hr as reported in Andover Report attachment.	$431,850	
101	Future Worth Factor	FWF		2.52	$FWF = i\left[\frac{1}{(1+i)^Y - 1}\right]$	0.14	0.14		0.31		0.23		0.23				0.23		0.23				0.23	
102	Years	Y	yr	2.53	$Y = \frac{h_{catalyst}}{CF_{SCR} \times 8760}$	6	6		3		4		4				4		4				4	
103	Factor for Catalyst Replacement	R_{layer}				3	3		3		3		3				3		3				3	
104	Annual Catalyst Replacement Cost		$/yr	2.50 + 2.51	$Annual\ Catalyst\ Replacement\ Cost = FWF \times Vol_{catalyst} \times \frac{CC_{replace}}{R_{layer}}$	$68,871	$68,871		$255,855		$189,828		$189,828		$388,156	Based on $0.25/MW-hr as reported in Andover Report attachment.	$468,745	EPA formula excludes number of reactors. This formula has been updated to reflect catalyst in multiple reactors must be changed	$468,745	EPA formula excludes number of reactors. This formula has been updated to reflect catalyst in multiple reactors must be changed	$388,156	Based on $0.25/MW-hr as reported in Andover Report attachment.	$468,745	EPA formula excludes number of reactors. This formula has been updated to reflect catalyst in multiple reactors must be changed
105	Annual Additional Water for Urea		$/yr		Volumetric flow rate of water, Dry Urea Consumption Rate * 1 lb H2O * 7.48 gal / (62.4 lb/ft3 * 1 lb urea)				$0		$1,464	Additional water would be needed for a U2A solid urea system in comparison with any other system because need the water to dissolve the solid urea. Value is based on gph flow rate of 50% urea solution.	$1,464		$0	Not included in Andover Report attachment.	$0		$0		$0	Not included in Andover Report attachment.	$0	
106	Annual Additional Steam for Urea Hydrolyzer		$/yr						$0		$73,260	Naughton 3 had 0.006MMBtu/hr of steam guaranteed per pound of urea consumed.	$73,260		$7,763	Based on $0.005/MW-hr as reported in Andover Report attachment.	$0		$0		$7,763	Based on $0.005/MW-hr as reported in Andover Report attachment.	$0	
107	Total Variable Direct Cost				=Electricity Cost+Reagent Solution Cost + Annual Catalyst Replacement Cost + Water Cost	$396,843	$294,290		$1,090,803		$1,111,723		$1,160,337		$1,234,335		$1,143,275		$1,143,275		$1,234,335		$1,143,275	
108	Total Direct Annual Cost			2.45	=Maintenance Cost +Total Variable Direct Cost	$541,681	$438,352		$1,333,220		$1,354,148		$1,570,107		$1,597,635		$3,474,571	+ Property Tax Factor PacifiCorp is subject to property taxes, per EPA cost manual 0.01*TCI was used.	$3,692,696	+ Property Tax Factor PacifiCorp is subject to property taxes, per EPA cost manual 0.01*TCI was used.	$1,597,635		$3,474,571	+ Property Tax Factor PacifiCorp is subject to property taxes, per EPA cost manual 0.01*TCI was used.
109	Property Tax Factor	F(tax)		2.5.5.8		0.00	0.00		0.00		0.00		0.00		0.00		$932,519		$1,019,769		0.00		$932,519	
110	Overhead Factor	F(ovhd)				0.00	0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00	
111	Capital Recovery Factor	CRF		2.55	$CRF = \frac{i(1+i)^n}{(1+i)^n - 1}$	0.0944	0.0944		0.0944		0.0944		0.0944		0.1064	Based on a capital recovery factor of 9.44% and a property taxes and insurance rate of 1.20%, Total Charge Rate = 10.64%.	0.0944		0.0944		0.1454	Based on a capital recovery factor of 9.44% and a property taxes and insurance rate of 1.20%, Total Charge Rate = 10.64%.	0.1334	
112	Indirect Annual Costs	IDAC	$/yr	2.54	$IDAC = CRF \times TCI$	$911,444	$906,564		$1,525,497		$1,525,546		$2,578,629		$5,814,581		$8,802,316		$9,625,894		$7,945,865		$12,435,779	
113	Total Annual Cost	TAC	$/yr	2.56	[illegible]	**$1,453,125**	**$1,344,916**		**$2,858,717**		**$2,879,694**		**$4,148,735**		**$7,959,487**	As reported in Andover Report attachment.	**$12,276,887**		**$13,318,590**		**$9,543,500**	As reported in Andover Report attachment.	**$15,910,351**	
114	Annual NOx Removed		tons/yr	2.57	NOx Removed	864	680		1,758		1,758		1,758		1,336	As reported in Andover Report attachment. (See Note 1)	1,336	Aligned with Andover Report assumption for cost-effectiveness comparison.	1,336	Aligned with Andover Report assumption for cost-effectiveness comparison.	1,336	As reported in Andover Report attachment. (See Note 1)	1,336	Aligned with Andover Report assumption for cost-effectiveness comparison.
115	Cost Effectiveness		$/ton	2.58	$Cost\ Effectiveness = \frac{TAC}{NO_x\ Removed}$	**$1,681**	**$1,978**		**$1,627**		**$1,639**		**$2,361**		**$5,956**	**As reported in Andover Report attachment. (See Note 1)**	**$9,189**		**$9,969**		**$7,143**	**As reported in Andover Report attachment. (See Note 1)**	**$11,909**	
116	**Note 1 - In attachment EPA-R08-OAR-2012-0026-0087, Andover calculates SCR cost effectiveness in two ways: a) starting from baseline emissions of 0.21, assuming combustion controls already in place (see worksheet "NOx - SCR_01_03")and b) starting from baseline emissions of 0.52, assuming combustion controls are not in place (see worksheet "Naughton"). This worksheet reports Andover's results assuming combustion controls are already in place since this is consistent with current operation at Naughton**																							

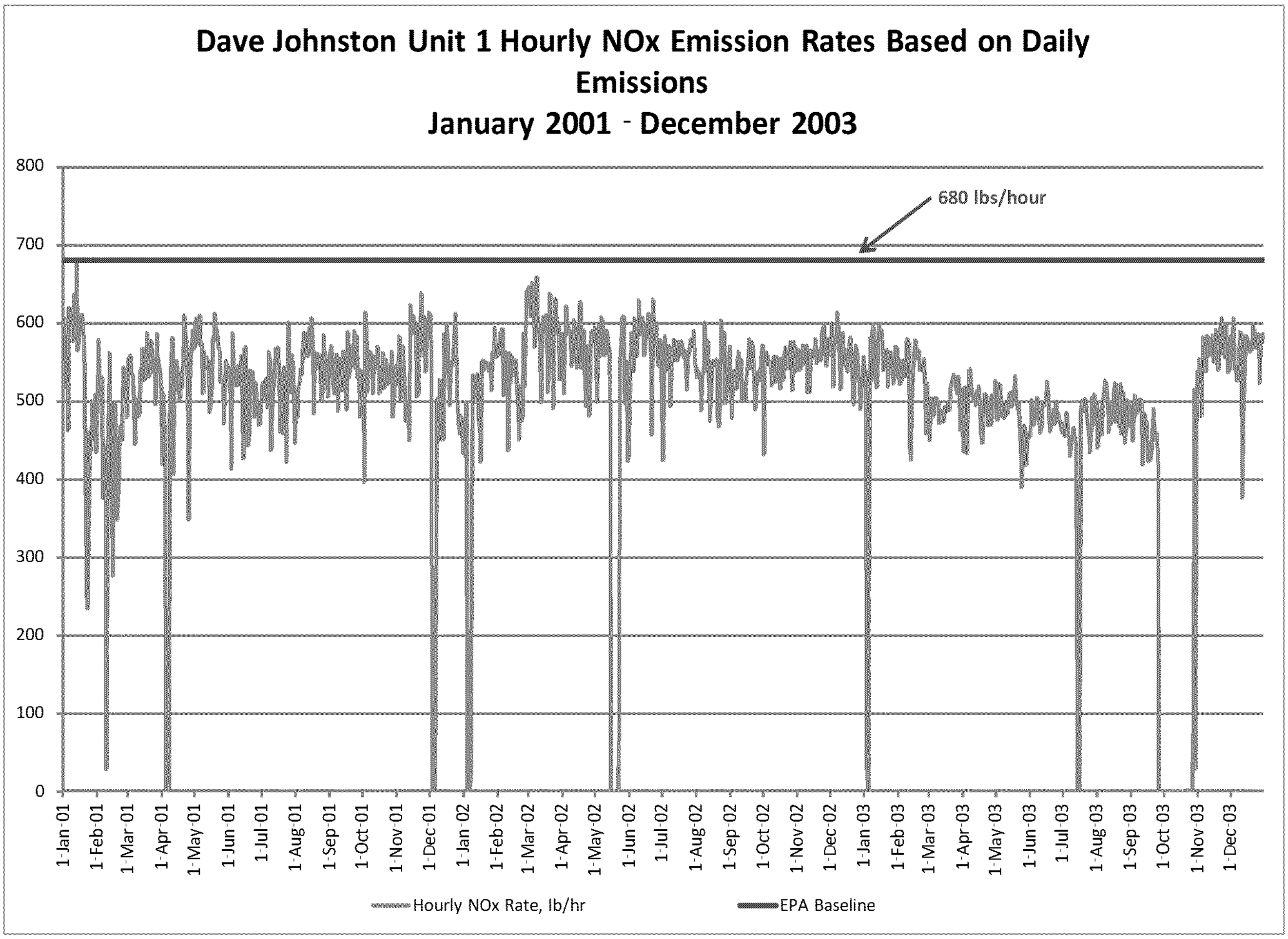
Attachment 5

EPA-R8-2014-0028860001469

General SCR Project Timeline – 2018 In-service



Attachment 6


Dave Johnston Unit 1 Hourly NOx Emission Rates Based on Daily Emissions
January 2001 - December 2003
680 lbs/hour
800
700
600
500
400
300
200
100
0
1-Jan-01
1-Feb-01
1-Mar-01
1-Apr-01
1-May-01
1-Jun-01
1-Jul-01
1-Aug-01
1-Sep-01
1-Oct-01
1-Nov-01
1-Dec-01
1-Jan-02
1-Feb-02
1-Mar-02
1-Apr-02
1-May-02
1-Jun-02
1-Jul-02
1-Aug-02
1-Sep-02
1-Oct-02
1-Nov-02
1-Dec-02
1-Jan-03
1-Feb-03
1-Mar-03
1-Apr-03
1-May-03
1-Jun-03
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1-Oct-03
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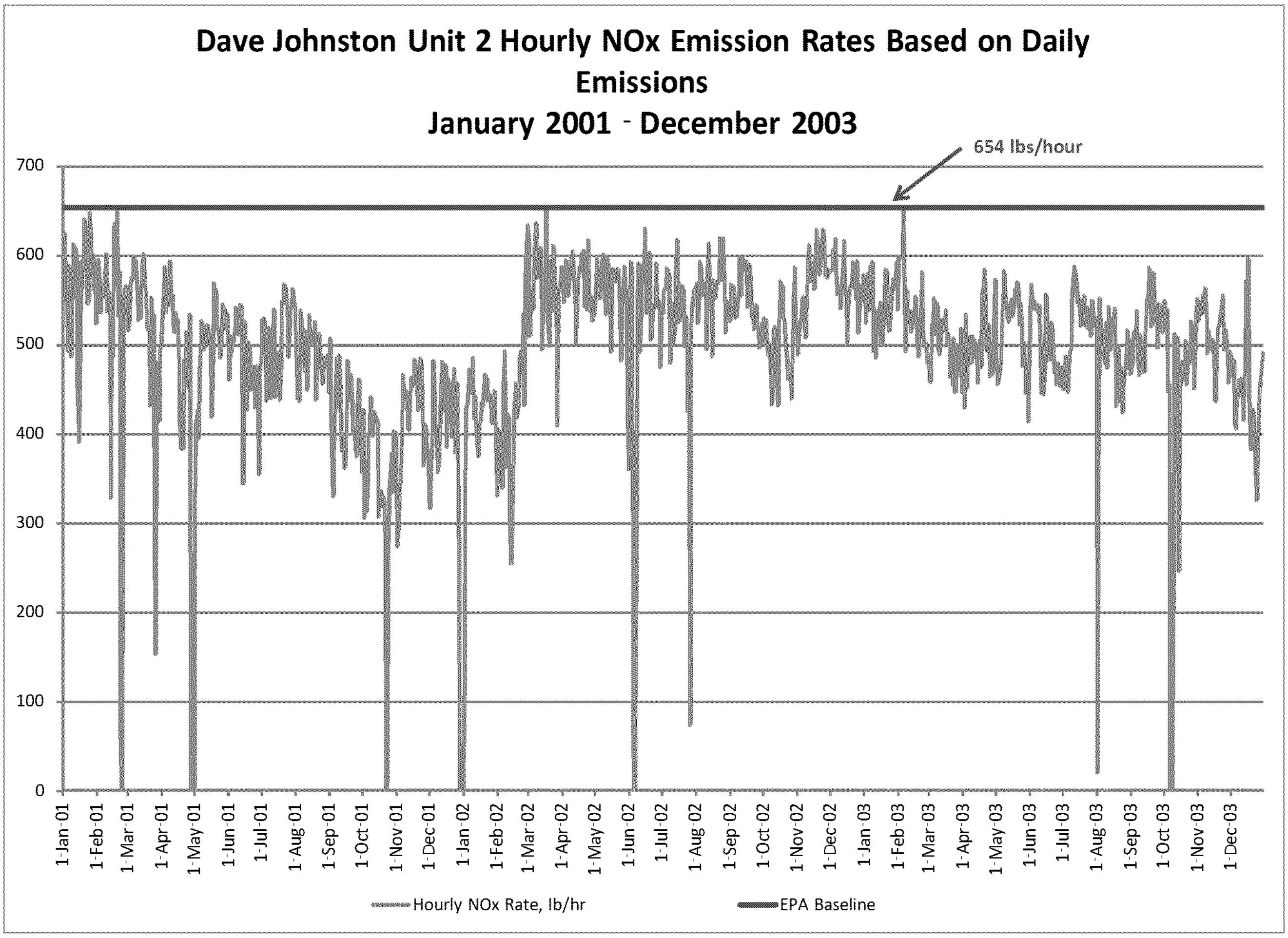
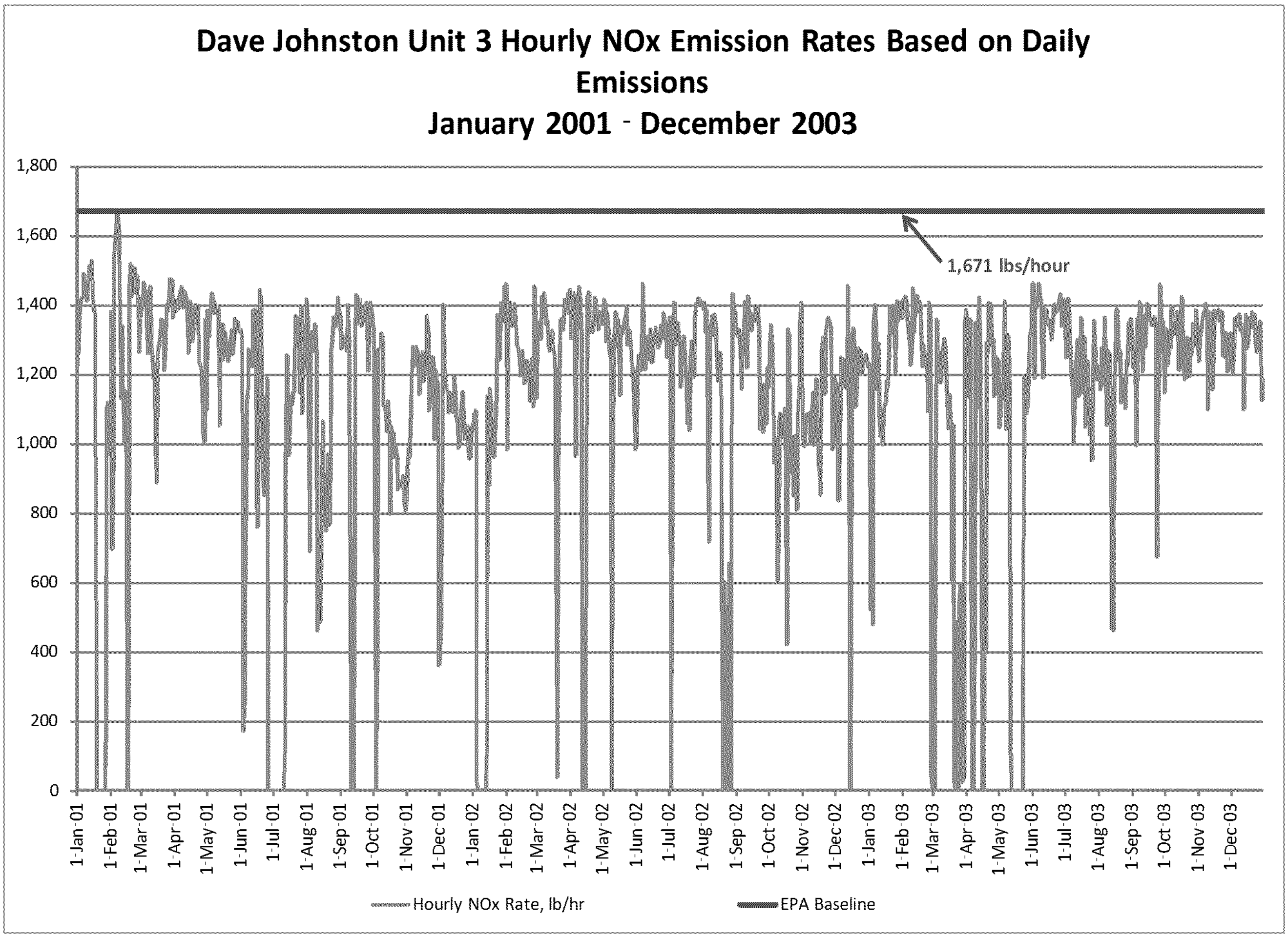
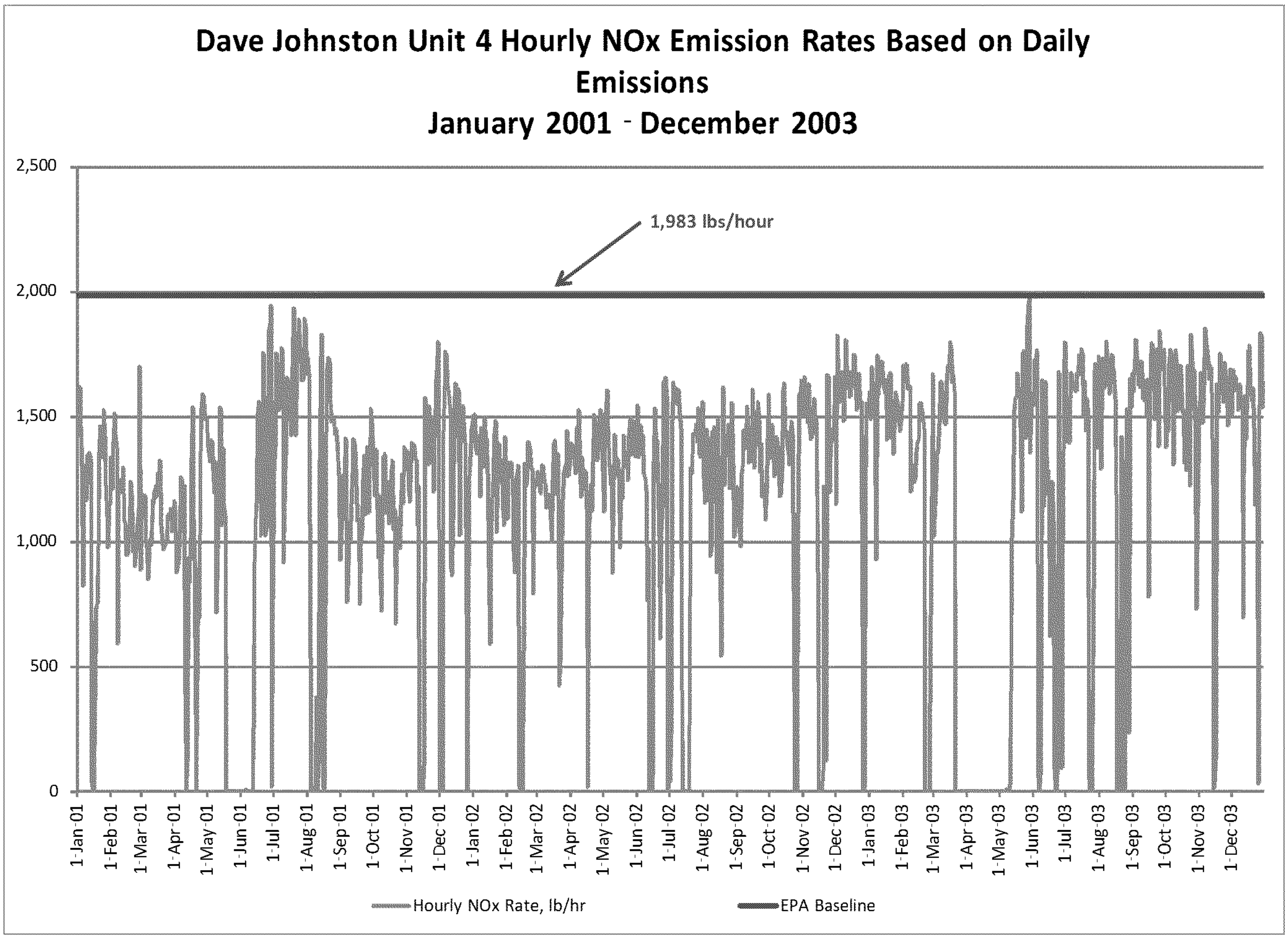
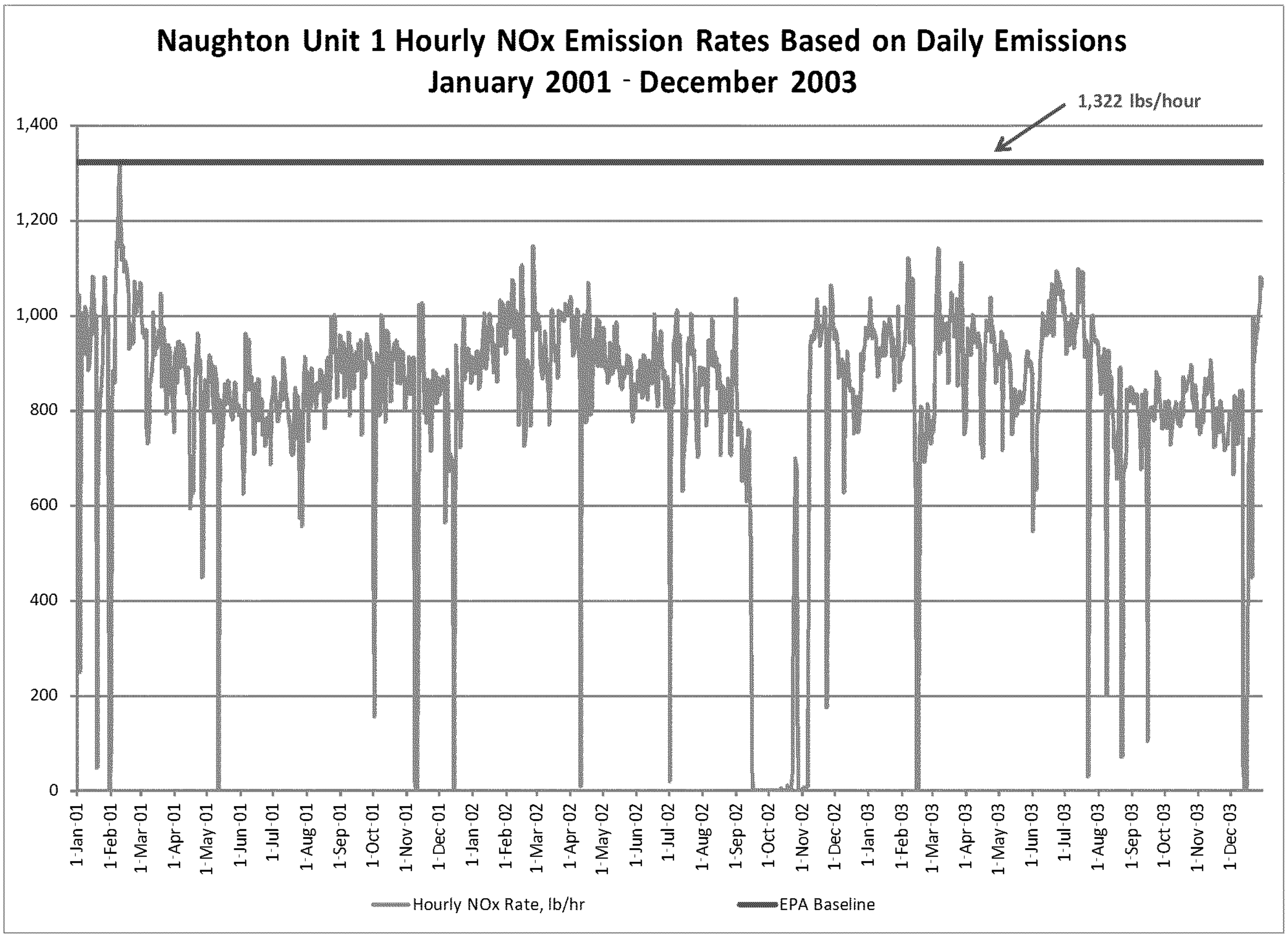
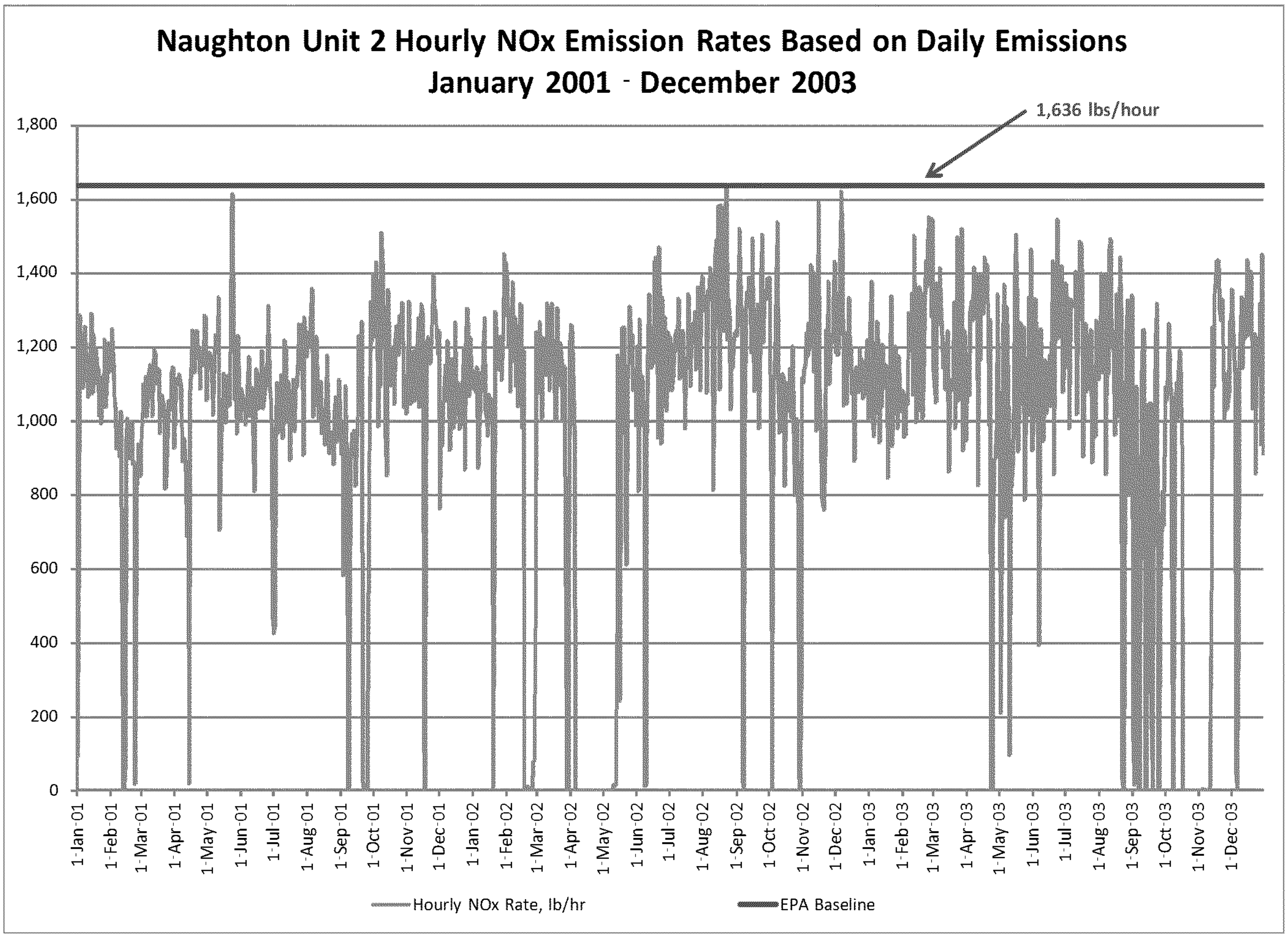
1-Dec-03
Hourly NOx Rate, lb/hr
EPA Baseline

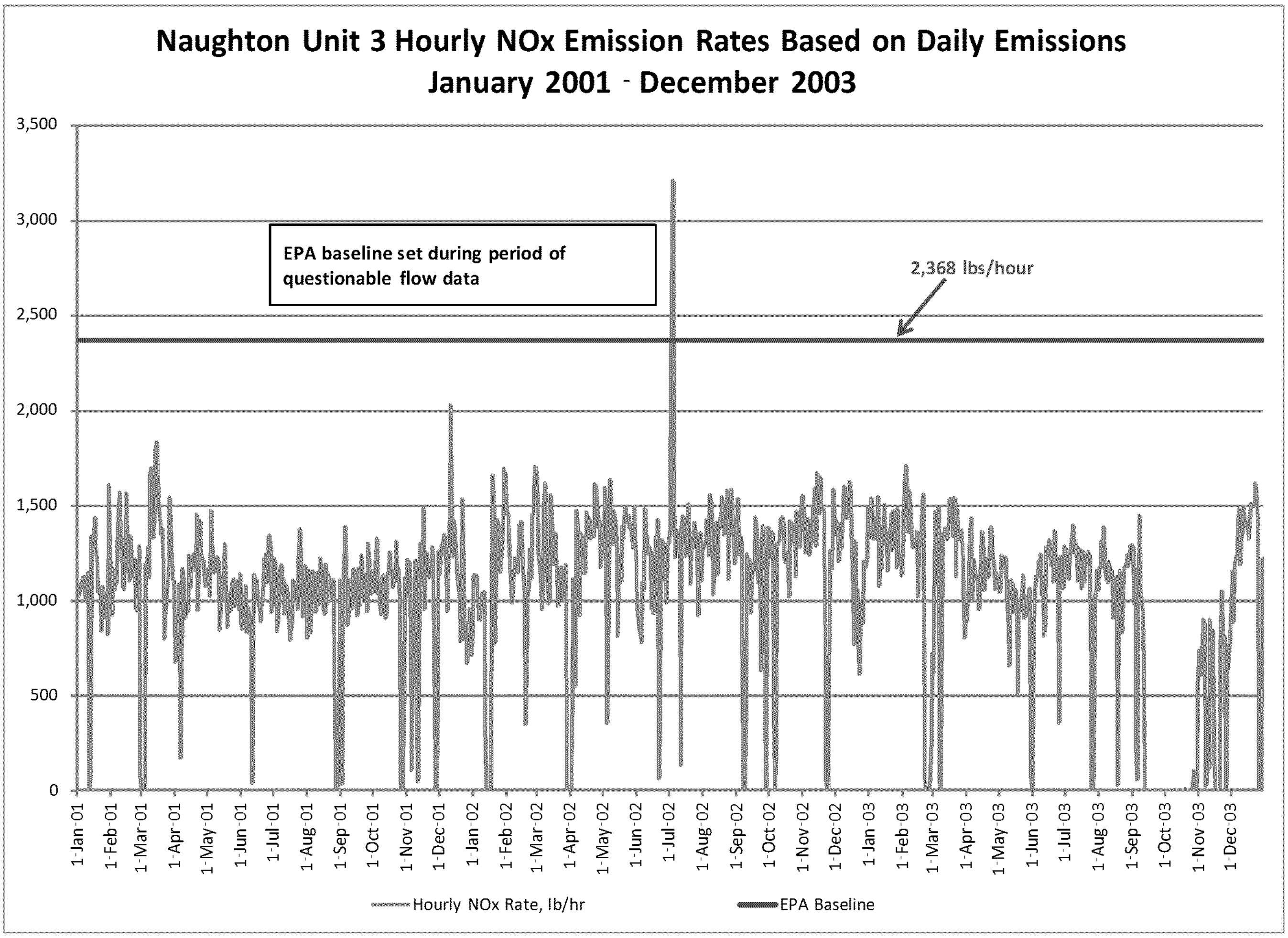

Dave Johnston Unit 2 Hourly NOx Emission Rates Based on Daily Emissions
January 2001 - December 2003
654 lbs/hour
700
600
500
400
300
200
100
0
1-Jan-01
1-Feb-01
1-Mar-01
1-Apr-01
1-May-01
1-Jun-01
1-Jul-01
1-Aug-01
1-Sep-01
1-Oct-01
1-Nov-01
1-Dec-01
1-Jan-02
1-Feb-02
1-Mar-02
1-Apr-02
1-May-02
1-Jun-02
1-Jul-02
1-Aug-02
1-Sep-02
1-Oct-02
1-Nov-02
1-Dec-02
1-Jan-03
1-Feb-03
1-Mar-03
1-Apr-03
1-May-03
1-Jun-03
1-Jul-03
1-Aug-03
1-Sep-03
1-Oct-03
1-Nov-03
1-Dec-03
Hourly NOx Rate, lb/hr
EPA Baseline


Dave Johnston Unit 3 Hourly NOx Emission Rates Based on Daily Emissions
January 2001 - December 2003
1,800
1,600
1,400
1,200
1,000
800
600
400
200
0
1,671 lbs/hour
1-Jan-01
1-Feb-01
1-Mar-01
1-Apr-01
1-May-01
1-Jun-01
1-Jul-01
1-Aug-01
1-Sep-01
1-Oct-01
1-Nov-01
1-Dec-01
1-Jan-02
1-Feb-02
1-Mar-02
1-Apr-02
1-May-02
1-Jun-02
1-Jul-02
1-Aug-02
1-Sep-02
1-Oct-02
1-Nov-02
1-Dec-02
1-Jan-03
1-Feb-03
1-Mar-03
1-Apr-03
1-May-03
1-Jun-03
1-Jul-03
1-Aug-03
1-Sep-03
1-Oct-03
1-Nov-03
1-Dec-03
Hourly NOx Rate, lb/hr
EPA Baseline


Dave Johnston Unit 4 Hourly NOx Emission Rates Based on Daily Emissions
January 2001 - December 2003
1,983 lbs/hour
2,500
2,000
1,500
1,000
500
0
1-Jan-01
1-Feb-01
1-Mar-01
1-Apr-01
1-May-01
1-Jun-01
1-Jul-01
1-Aug-01
1-Sep-01
1-Oct-01
1-Nov-01
1-Dec-01
1-Jan-02
1-Feb-02
1-Mar-02
1-Apr-02
1-May-02
1-Jun-02
1-Jul-02
1-Aug-02
1-Sep-02
1-Oct-02
1-Nov-02
1-Dec-02
1-Jan-03
1-Feb-03
1-Mar-03
1-Apr-03
1-May-03
1-Jun-03
1-Jul-03
1-Aug-03
1-Sep-03
1-Oct-03
1-Nov-03
1-Dec-03
Hourly NOx Rate, lb/hr
EPA Baseline


Naughton Unit 1 Hourly NOx Emission Rates Based on Daily Emissions
January 2001 - December 2003
1,322 lbs/hour
1,400
1,200
1,000
800
600
400
200
0
1-Jan-01
1-Feb-01
1-Mar-01
1-Apr-01
1-May-01
1-Jun-01
1-Jul-01
1-Aug-01
1-Sep-01
1-Oct-01
1-Nov-01
1-Dec-01
1-Jan-02
1-Feb-02
1-Mar-02
1-Apr-02
1-May-02
1-Jun-02
1-Jul-02
1-Aug-02
1-Sep-02
1-Oct-02
1-Nov-02
1-Dec-02
1-Jan-03
1-Feb-03
1-Mar-03
1-Apr-03
1-May-03
1-Jun-03
1-Jul-03
1-Aug-03
1-Sep-03
1-Oct-03
1-Nov-03
1-Dec-03
Hourly NOx Rate, lb/hr
EPA Baseline


Naughton Unit 2 Hourly NOx Emission Rates Based on Daily Emissions
January 2001 - December 2003
1,636 lbs/hour
1,800
1,600
1,400
1,200
1,000
800
600
400
200
0
1-Jan-01
1-Feb-01
1-Mar-01
1-Apr-01
1-May-01
1-Jun-01
1-Jul-01
1-Aug-01
1-Sep-01
1-Oct-01
1-Nov-01
1-Dec-01
1-Jan-02
1-Feb-02
1-Mar-02
1-Apr-02
1-May-02
1-Jun-02
1-Jul-02
1-Aug-02
1-Sep-02
1-Oct-02
1-Nov-02
1-Dec-02
1-Jan-03
1-Feb-03
1-Mar-03
1-Apr-03
1-May-03
1-Jun-03
1-Jul-03
1-Aug-03
1-Sep-03
1-Oct-03
1-Nov-03
1-Dec-03
Hourly NOx Rate, lb/hr
EPA Baseline


Naughton Unit 3 Hourly NOx Emission Rates Based on Daily Emissions
January 2001 - December 2003
3,500
3,000
2,500
2,000
1,500
1,000
500
0
EPA baseline set during period of questionable flow data
2,368 lbs/hour
1-Jan-01
1-Feb-01
1-Mar-01
1-Apr-01
1-May-01
1-Jun-01
1-Jul-01
1-Aug-01
1-Sep-01
1-Oct-01
1-Nov-01
1-Dec-01
1-Jan-02
1-Feb-02
1-Mar-02
1-Apr-02
1-May-02
1-Jun-02
1-Jul-02
1-Aug-02
1-Sep-02
1-Oct-02
1-Nov-02
1-Dec-02
1-Jan-03
1-Feb-03
1-Mar-03
1-Apr-03
1-May-03
1-Jun-03
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1-Sep-03
1-Oct-03
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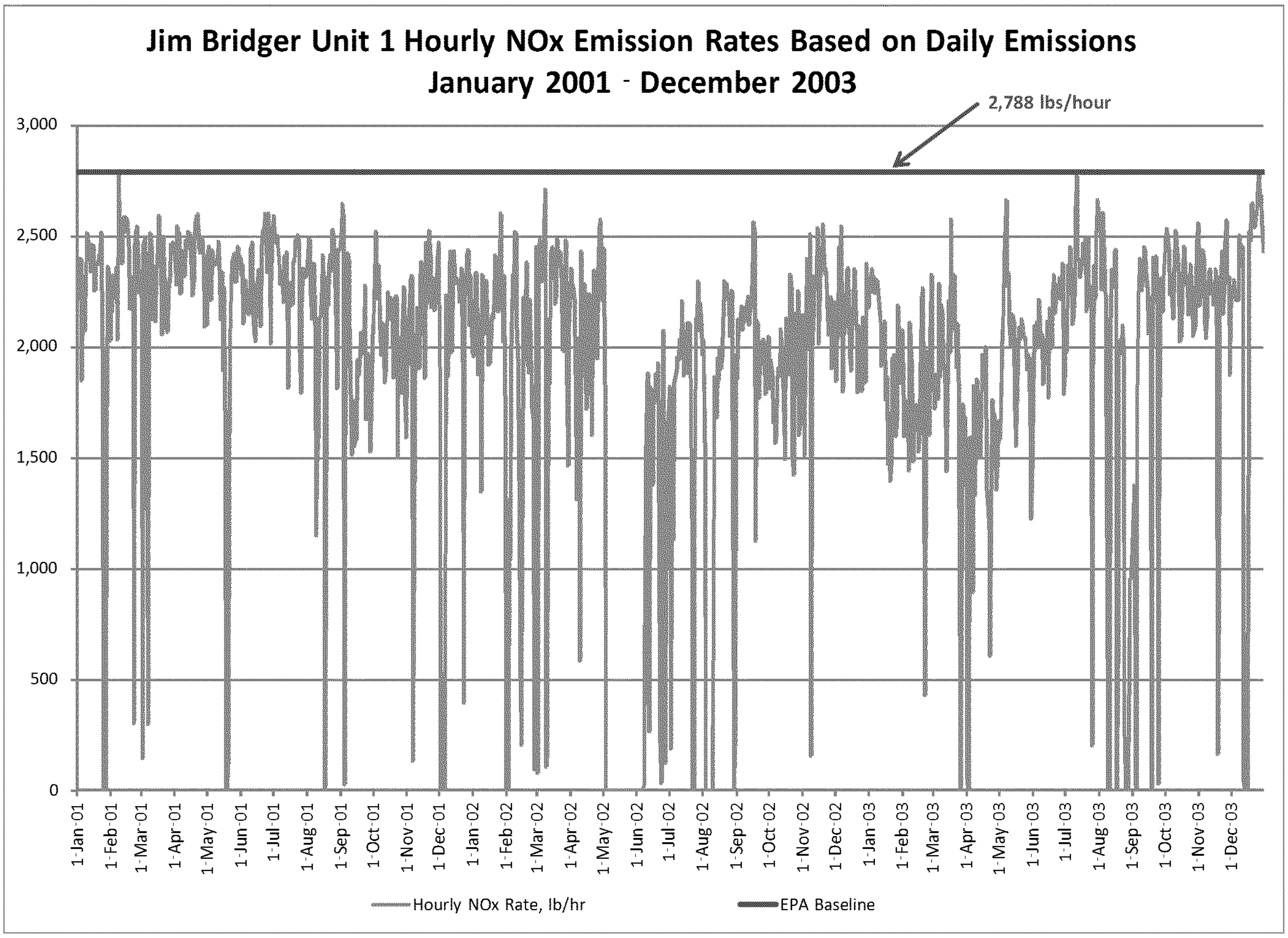
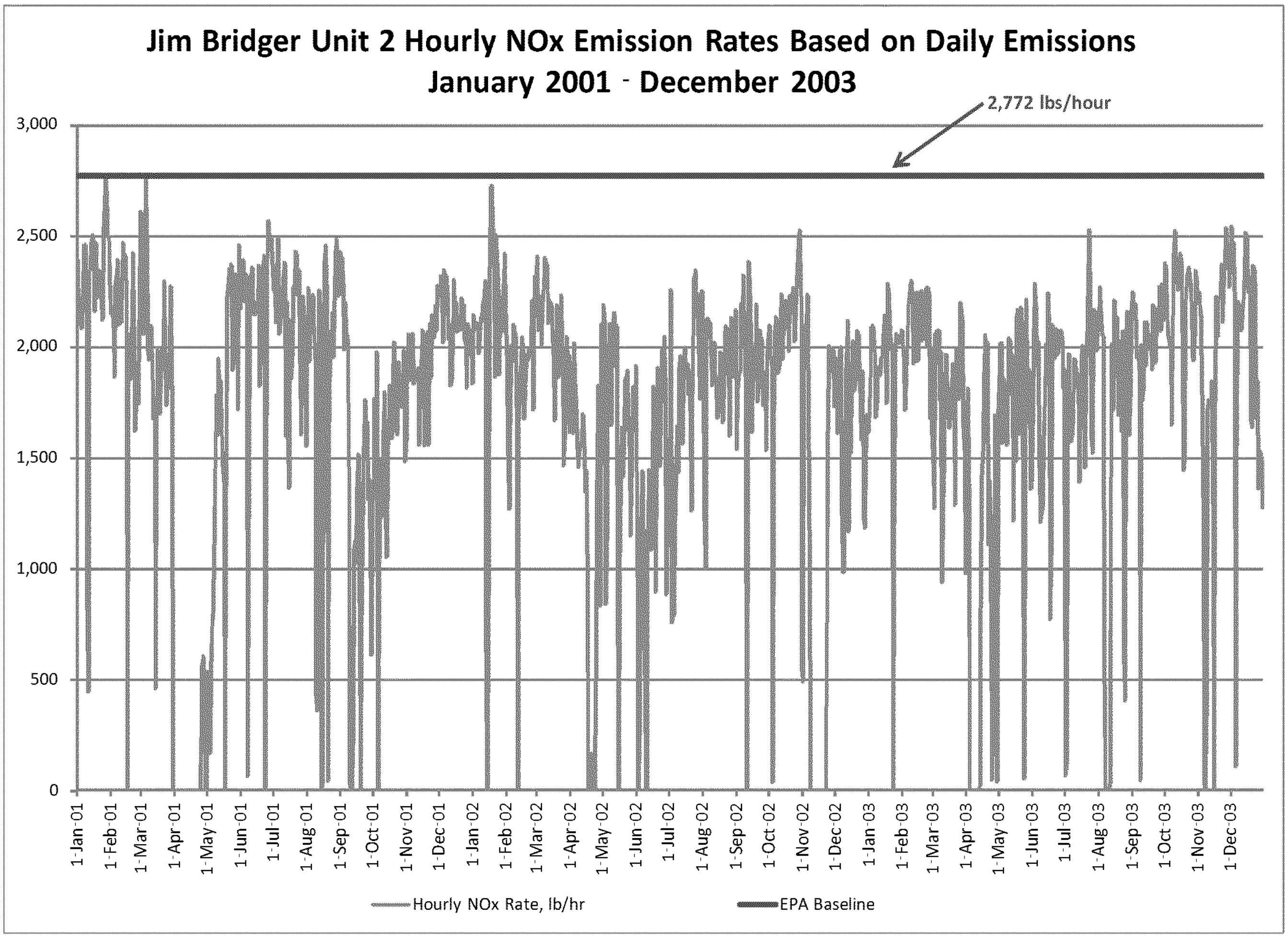
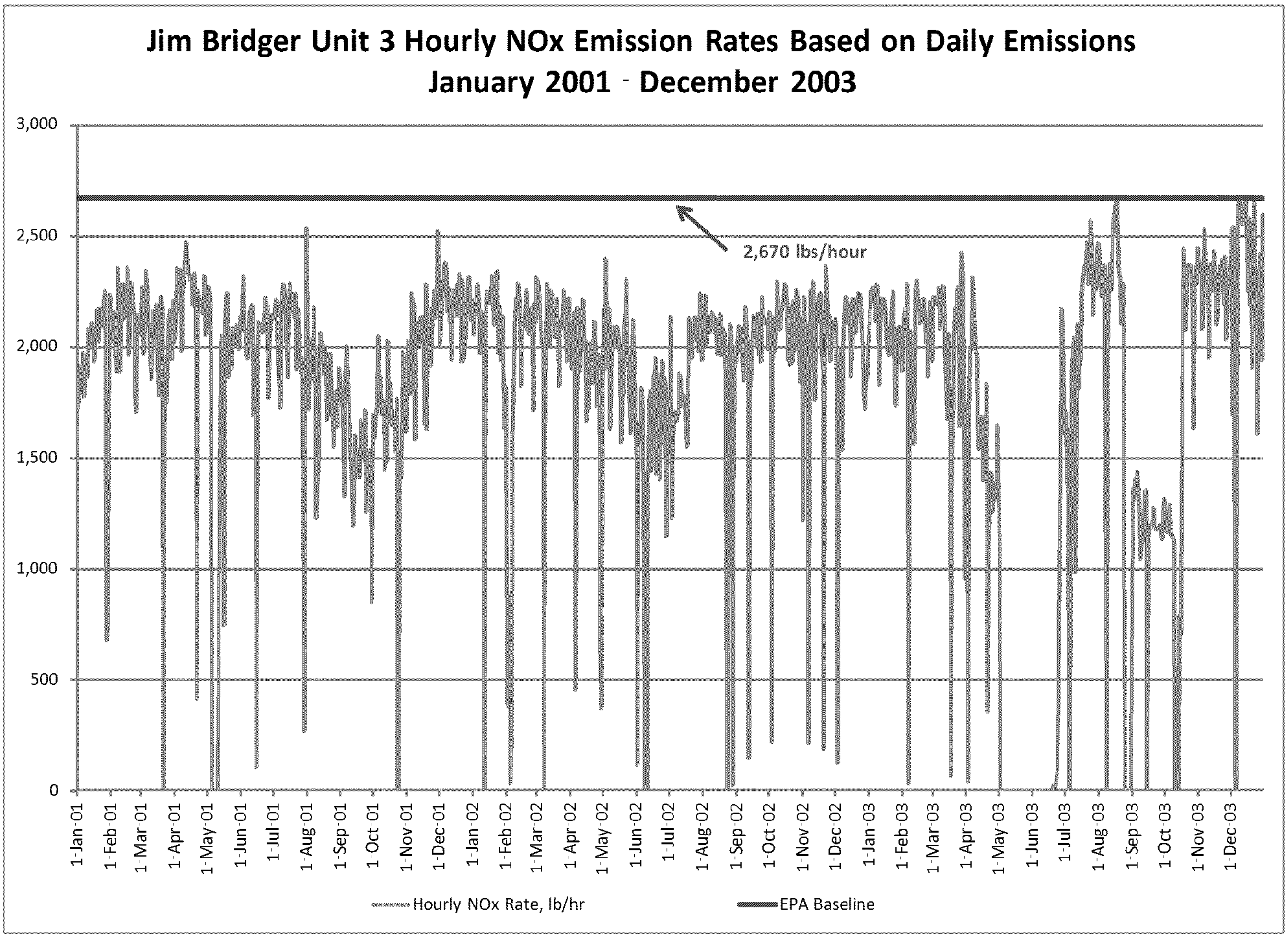
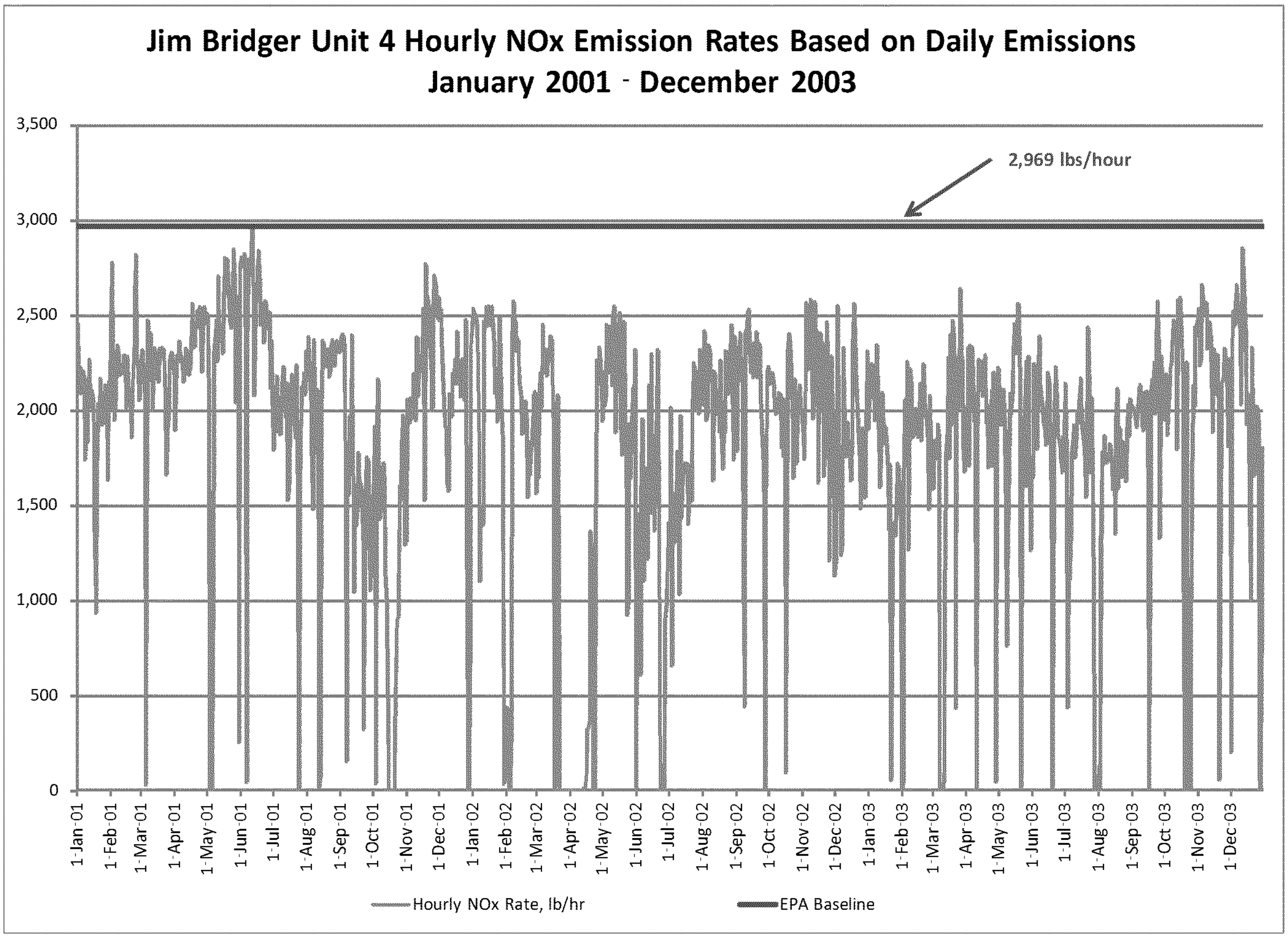
1-Dec-03
Hourly NOx Rate, lb/hr
EPA Baseline


Jim Bridger Unit 1 Hourly NOx Emission Rates Based on Daily Emissions
January 2001 - December 2003
2,788 lbs/hour
3,000
2,500
2,000
1,500
1,000
500
0
1-Jan-01
1-Feb-01
1-Mar-01
1-Apr-01
1-May-01
1-Jun-01
1-Jul-01
1-Aug-01
1-Sep-01
1-Oct-01
1-Nov-01
1-Dec-01
1-Jan-02
1-Feb-02
1-Mar-02
1-Apr-02
1-May-02
1-Jun-02
1-Jul-02
1-Aug-02
1-Sep-02
1-Oct-02
1-Nov-02
1-Dec-02
1-Jan-03
1-Feb-03
1-Mar-03
1-Apr-03
1-May-03
1-Jun-03
1-Jul-03
1-Aug-03
1-Sep-03
1-Oct-03
1-Nov-03
1-Dec-03
Hourly NOx Rate, lb/hr
EPA Baseline

EPA-R8-2014-0028860001469




Jim Bridger Unit 3 Hourly NOx Emission Rates Based on Daily Emissions
January 2001 - December 2003
3,000
2,500
2,000
1,500
1,000
500
0
2,670 lbs/hour
1-Jan-01
1-Feb-01
1-Mar-01
1-Apr-01
1-May-01
1-Jun-01
1-Jul-01
1-Aug-01
1-Sep-01
1-Oct-01
1-Nov-01
1-Dec-01
1-Jan-02
1-Feb-02
1-Mar-02
1-Apr-02
1-May-02
1-Jun-02
1-Jul-02
1-Aug-02
1-Sep-02
1-Oct-02
1-Nov-02
1-Dec-02
1-Jan-03
1-Feb-03
1-Mar-03
1-Apr-03
1-May-03
1-Jun-03
1-Jul-03
1-Aug-03
1-Sep-03
1-Oct-03
1-Nov-03
1-Dec-03
Hourly NOx Rate, lb/hr
EPA Baseline


Jim Bridger Unit 4 Hourly NOx Emission Rates Based on Daily Emissions
January 2001 - December 2003
2,969 lbs/hour
3,500
3,000
2,500
2,000
1,500
1,000
500
0
1-Jan-01
1-Feb-01
1-Mar-01
1-Apr-01
1-May-01
1-Jun-01
1-Jul-01
1-Aug-01
1-Sep-01
1-Oct-01
1-Nov-01
1-Dec-01
1-Jan-02
1-Feb-02
1-Mar-02
1-Apr-02
1-May-02
1-Jun-02
1-Jul-02
1-Aug-02
1-Sep-02
1-Oct-02
1-Nov-02
1-Dec-02
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1-Feb-03
1-Mar-03
1-Apr-03
1-May-03
1-Jun-03
1-Jul-03
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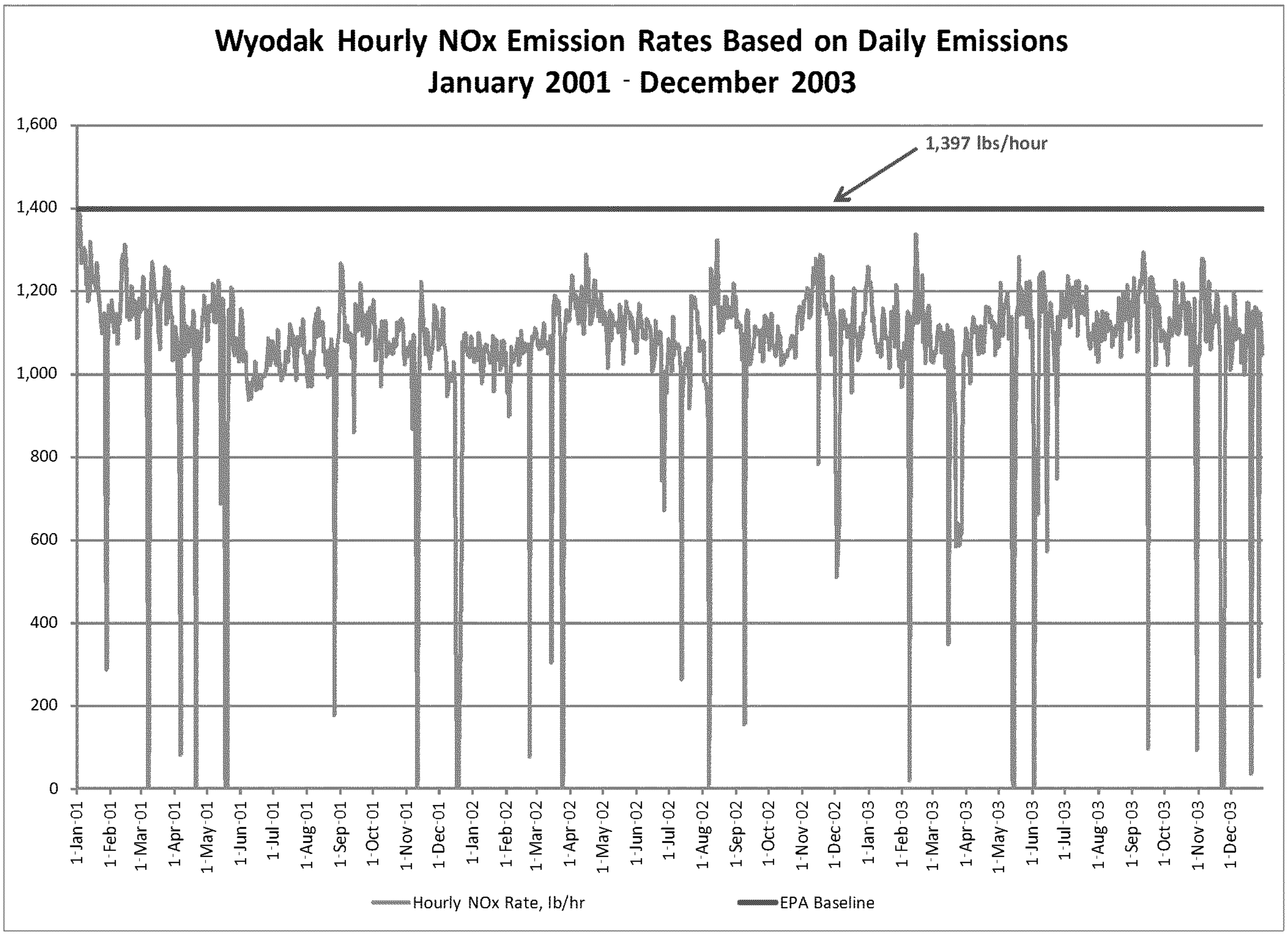
1-Sep-03
1-Oct-03
1-Nov-03
1-Dec-03
Hourly NOx Rate, lb/hr
EPA Baseline


Wyodak Hourly NOx Emission Rates Based on Daily Emissions
January 2001 - December 2003
1,397 lbs/hour
1,600
1,400
1,200
1,000
800
600
400
200
0
1-Jan-01
1-Feb-01
1-Mar-01
1-Apr-01
1-May-01
1-Jun-01
1-Jul-01
1-Aug-01
1-Sep-01
1-Oct-01
1-Nov-01
1-Dec-01
1-Jan-02
1-Feb-02
1-Mar-02
1-Apr-02
1-May-02
1-Jun-02
1-Jul-02
1-Aug-02
1-Sep-02
1-Oct-02
1-Nov-02
1-Dec-02
1-Jan-03
1-Feb-03
1-Mar-03
1-Apr-03
1-May-03
1-Jun-03
1-Jul-03
1-Aug-03
1-Sep-03
1-Oct-03
1-Nov-03
1-Dec-03
Hourly NOx Rate, lb/hr
EPA Baseline

Attachment 7

Preliminary Analysis of EPA Wyoming BART Modeling

PREPARED FOR: Bill Lawson, PacifiCorp

COPY TO:

PREPARED BY: CH2M Hill

DATE: August 3, 2012

PROJECT NUMBER:

CH2M Hill has obtained the modeling files from EPA Region 8 that they used to model the impact to regional visibility from PacifiCorp power plants in Wyoming. In reviewing these files, we have noted the following issues with the methods and data that EPA chose to use in performing this modeling.

Background Ammonia Concentration:
EPA conservatively used a constant 2 ppb ammonia for the WY BART modeling. This value is conservative based on Wyoming Land Use, IWAQM Guidance, WRAP protocols, and nearby State's BART modeling using monthly/seasonally varying ammonia.

IWAQM recommends 0.5 ppb for forest, 1ppb for dry/arid lands and 10ppb for agriculture/grassland. The state undergoes seasonal swings of dry-hot summers and snow covered ground in the winter. Therefore, the use of a single ammonia concentration for the entire year in a state where the land use and land cover changes significantly between seasons could result in unrealistic seasonal results. This would be particularly true in winter time when agricultural activity is minimal and meteorological conditions would make visibility calculations particularly sensitive to ambient ammonia concentrations.

WRAP recommended the use of 1 ppb year round for states in the region to account for the seasonal variability. Other states have allowed for the use of monthly varying ammonia concentrations to better reflect the monthly variations observed in monitored ambient data.

CALPUFF Model Version 5.7:
The most recent EPA approved version of CALPUFF is version 5.8 and was released on June 23, 2007. The EPA modeling of the WY coal plants used version 5.711a, released July 16, 2004. Since version 5.711a, EPA has subsequently released versions 5.711b, version 5.756, and the now currently approved version 5.8. EPA also released a Model update report (available at www.epa.gov/ttn/scra m) demonstrating that the bugs fixed and enhancements put into in version 5.8 warrant EPA using the recommend version 5.8 as the approved version of CALPUFF.

The modeling conducted by EPA with version 5.711a was completed in April 2012. This is eight years and three more recent CALPUFF model versions since the release of version 5.711a by EPA.

EPA has in recent years recommended the use of V5.8 for BACT analyses. Specifically, EPA Region 9 requested Catalyst Paper use V5.8 for their units in Arizona in a letter dated November 17, 2011. Also, the State of Utah (through guidance from EPA) has requested that PacifiCorp use V5.8 for recent BACT studies in Utah. The use of V5.7 in the WY coal plant studies is incongruent with recent EPA guidance.

CALPOST Method 6:

The previously preferred Method 6 simply computes background light extinction using monthly average relative humidity adjustment factors particular to each Class I Area applied to background and modeled sulfate and nitrate. Six years after the development of Method 6 in 1999, EPA released enhancements to the background light extinction equations, which use the IMPROVE variable extinction efficiency formulation. These enhancements take into account the fact that sulfates, nitrates and organics and other types of particles have different light extinction coefficients. Also the background concentrations at each Class I area have been updated by EPA to reflect natural background visibility condition estimates for each Class I area for each type of particle: ammonium sulfate, ammonium nitrate, organic matter, elemental carbon, soil, crustal material, sea salt and air molecules. Also, relative humidity adjustment factors have been tailored separately for: small particles, large particles, and sea salt background concentrations.

These new enhancements to the calculation method greatly improve the accuracy of the estimated visibility impact and are called Method 8. Method 8 was added to CALPOST in 2008 and was adopted as the preferred option for determining impacts on visibility by the Federal Land Managers Air Quality Related Values Work Group (FLAG) guidance document in 2010 (FLAG 2010) . The applicable background concentrations and relative humidity adjustment factors using Method 8 for each Class I area are identified in the FLAG 2010 manual.

Despite this update to Method 8 in 2008 and the stated preference by the FLMs in 2010 to use Method 8, EPA updated the WY BART modeling in 2012 using the long outdated and scientifically inferior Method 6. This modeling by EPA was done two years after the FLM recommendation to use Method 8 was published in 2010 and four years after Method 8 was incorporated into CALPOST by EPA. EPA's use of Method 6, and not Method 8, is arbitrary and capricious. EPA should have used Method 8, the "best" modeling science.

Attachment 8

Response to Prehearing Statements

Martin Drake Power Plant Best Available Retrofit Technology Rulemaking Hearing

AECOM, Bob Paine
AECOM, Jeffrey Connors
November 10, 2010

Mr. Paine has 35 years experience in the design and implementation of air quality models, meteorological analyses, permitting studies, field investigations, impact analysis of airborne toxic releases and expert witness testimony. Mr. Paine is a Certified Consulting Meteorologist, Qualified Environmental Professional and a member of the American Meteorological Society and of the Air and Waste Management Association. He holds a BS in Atmospheric Science from the State University of New York at Alabany and an MS in Meteorology from the Massachusetts Institute of Technology.

Over the course of his career, Mr. Paine has published over 100 articles for peer reviewed journals and technical conferences. His has also contributed to the development of technical portions of widely used models such as ISC and AERMOD.

As a recognized expert in atmospheric dispersion modeling, Mr. Paine has conducted the modeling required for the permitting of numerous facilities. His experience with a wide variety of air dispersion models and CALPUFF in particular makes him well-qualified to speak to issues involved in the use of CALPUFF modeling.

Colorado Springs Utilities requested that AECOM provide additional technical discussions for their rebuttal statement being submitted to the State of Colorado Air Quality Control Commission (The Commission) regarding Colorado's Regional Haze State Implementation Plan and Regulation No. 3, Part F Best Available Retrofit Technology (BART) Requirements. AECOM's technical discussion focuses on two key areas:

(1) Evaluation of potential benefits for regional haze from additional NO_X emission control on Drake; and
(2) Conservatism in the CALPUFF model related to particulate nitrate formation.

Evaluation of Potential Benefits for Regional Haze from Additional NO_X Control

In order to determine whether additional NO_X controls to Drake would result in improved regional haze at Rocky Mountain National Park, several back-trajectory analyses were conducted for days in which some elevated nitrate particulate was observed at the IMPROVE monitor. However, on many of those days, much of the haze was likely contributed by uncontrollable sources such as windblown dust and wildfire emissions. The back-trajectory analyses were conducted with the NOAA Air Resources Laboratory's HYSPLIT Trajectory Model. Access to the interactive trajectory model is available at: http://ready.arl.noaa.gov/HYSPLIT.php . A total of ten high nitrate days (which were designated as among the 20% worst haze days) were examined from during 2007 and 2008. The associated IMPROVE data composition plots are presented in Figures 1 and 2.

The NAM (Eta) 12 km forecast meteorological data was used to calculate back trajectories for the ten days; this database is not available prior to May 2007, so the events reviewed were for periods during or after May 2007. The back-trajectory starting point was set as the Rocky Mountain National Park IMPROVE monitor, shown in Figure 3 as a blue triangle. The back-trajectory analysis for each high nitrate day was started 24 hours prior to the event.

The resulting trajectory for each of the ten days is depicted in Figure 3. Figure 3 shows that none of the calculated trajectories originated at or near the Drake Power Plant. Most of the trajectories originated from the west and southwest of the Rocky Mountain National Park, and could be associated with areas of wildfire emissions. We did not find any events for which the trajectories led back to the Drake Plant location. Therefore, installing NO_x controls on Drake would not likely result in reduced concentrations of nitrates (and improvements to regional haze) at Rocky Mountain National Park.

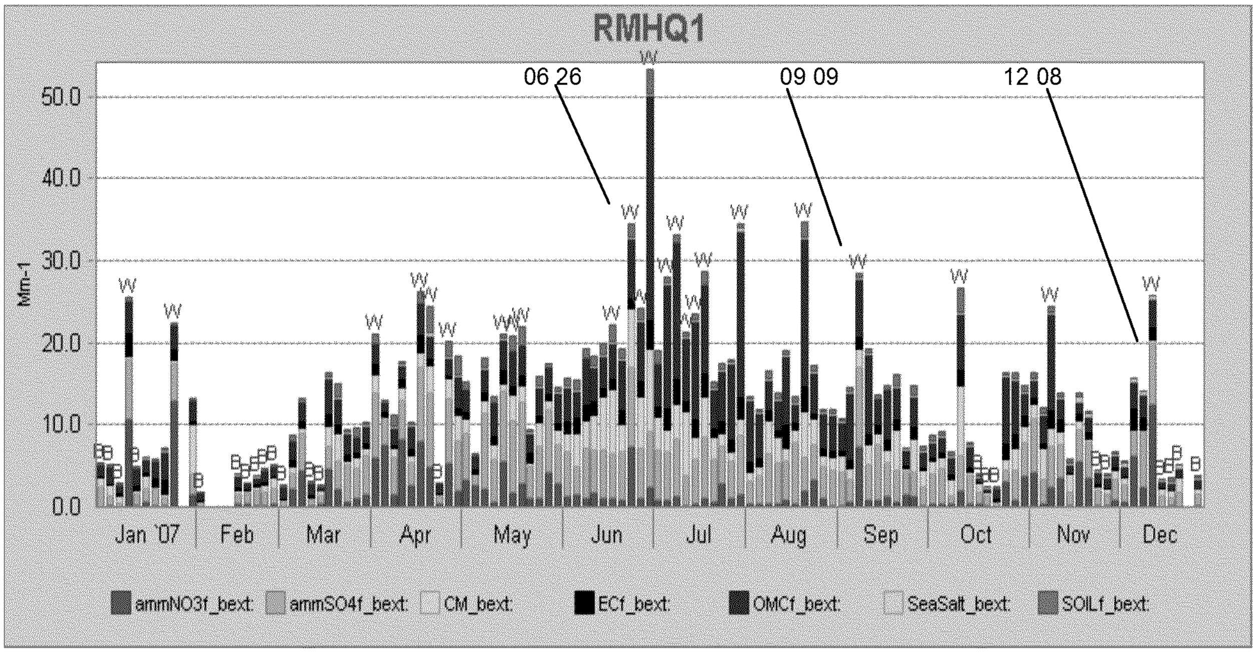


Figure 1. 2007 IMPROVE Composition Data for Rocky Mountain NP and High Nitrate Days.

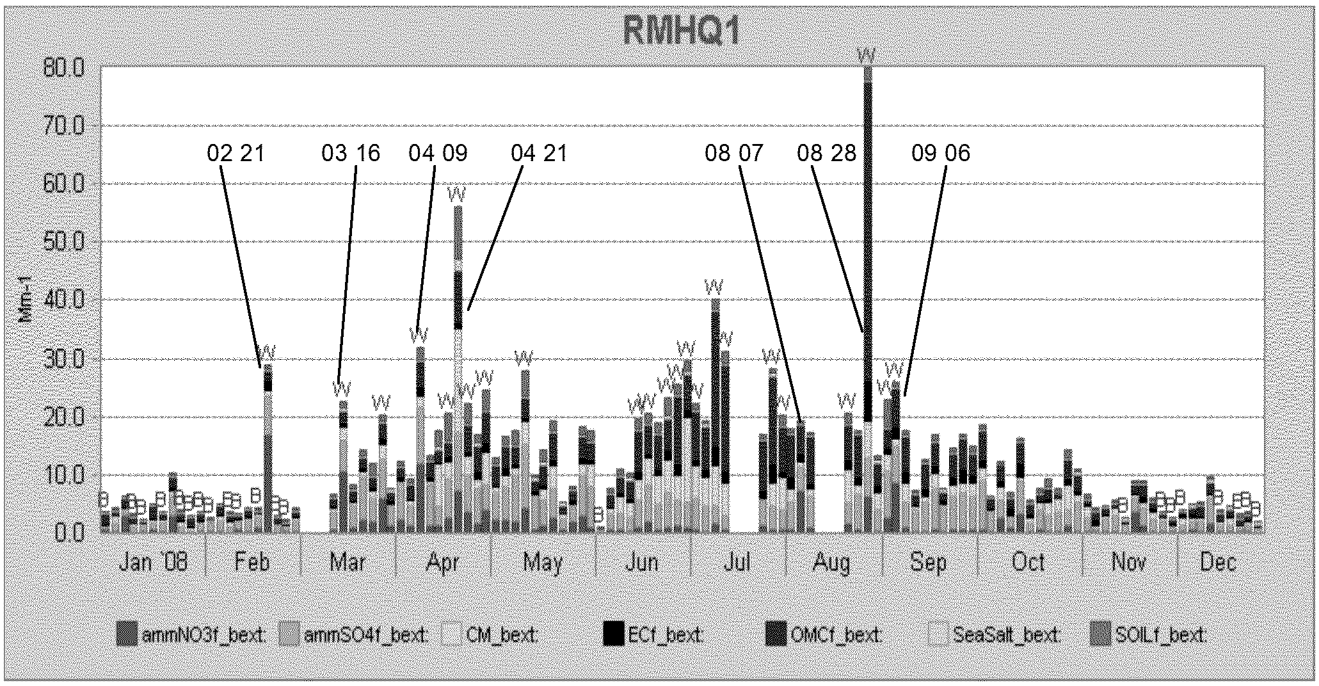


Figure 1. 2008 IMPROVE Composition Data for Rocky Mountain NP and High Nitrate Days.

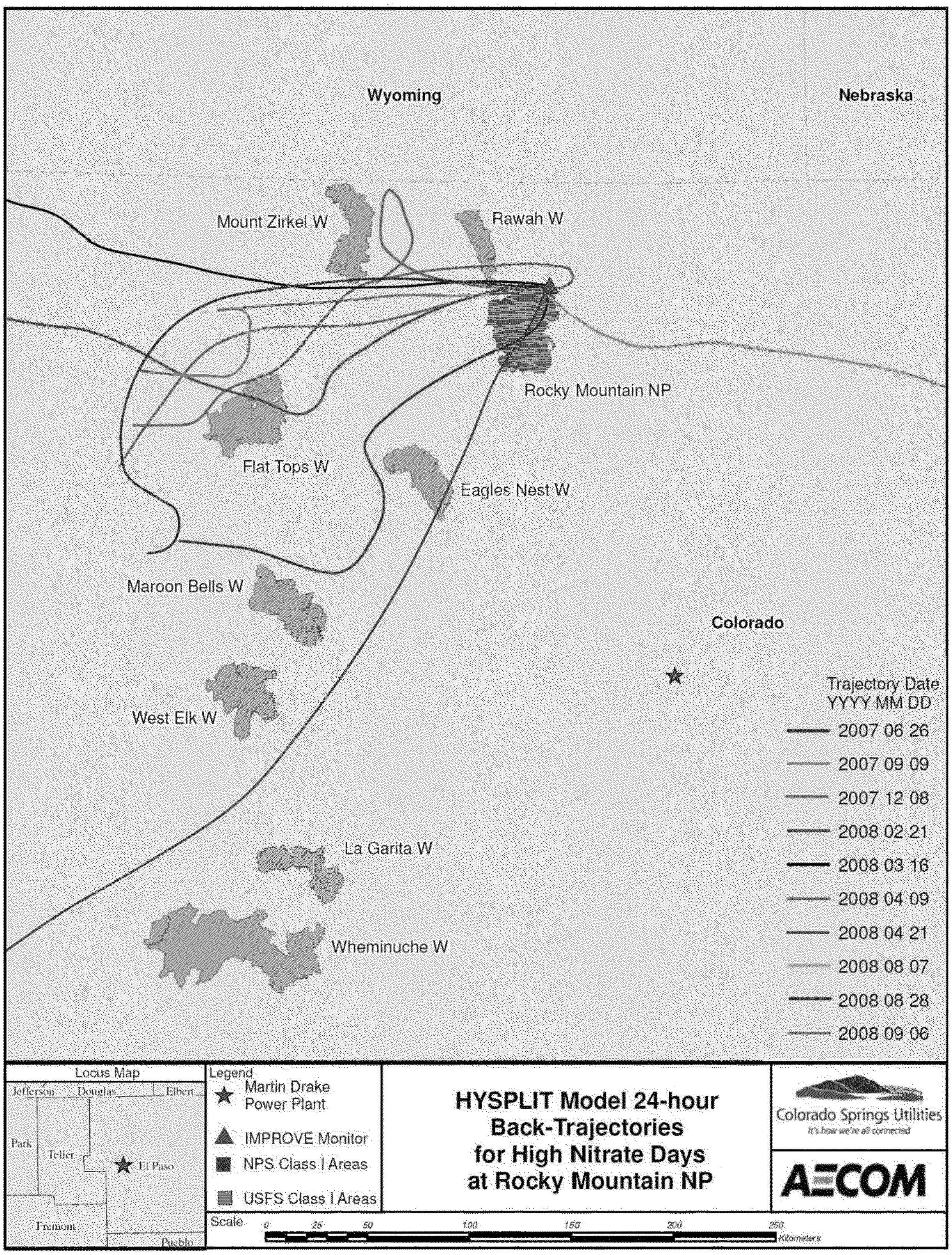


Figure 3. HYSPLIT Model 24-hour Back-Trajectories for High Nitrate Days in 2007 and 2008.

CALPUFF Model Conservatism Related to Nitrate Formation

The focus of the technical discussion is on CALPUFF's conservatism in predicting nitrate and the importance of background ammonia in the ability of CALPUFF to more accurately predict nitrate formation. In addition, this section discusses a recent model enhancement to CALPUFF designed to improve CALPUFF's ability to predict nitrate formation.

Secondary pollutants such as nitrates and sulfates contribute to light extinction in Class I areas. The CALPUFF model was approved by EPA for use in BART determinations to evaluate the effect of these pollutants on visibility in Class I areas. CALPUFF uses the EPA-approved MESOPUFF II chemical reaction mechanism to convert SO_2 and NO_x emissions to secondary sulfates and nitrates. This section describes how secondary pollutants, specifically nitrates, are formed and the factors affecting their formation, especially as formulated in CALPUFF.

In the CALPUFF model, the oxidation of NO_x to nitric acid (HNO_3) depends on the NO_x concentration, ambient ozone concentration, and atmospheric stability. Some of the nitric acid is then combined with available ammonia in the atmosphere to form ammonium nitrate aerosol in an equilibrium state that is a function of temperature, relative humidity, and ambient ammonia concentration, as shown in Figure 4 (taken from the CALPUFF user's guide).

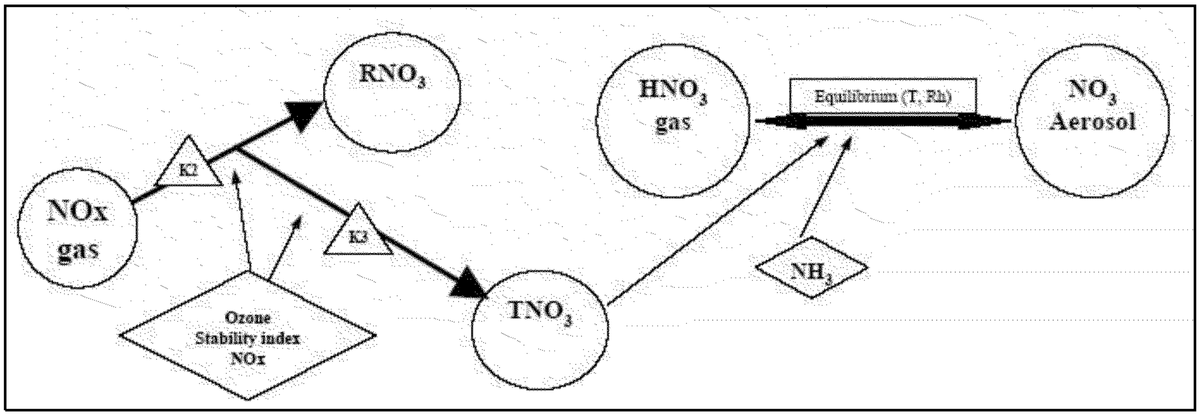


Figure 4. MESOPUFF II NOx Oxidation.

Role of Background Ammonia in CALPUFF

In CALPUFF, total nitrate ($TNO_3 = HNO_3 + NO_3$) is partitioned into gaseous HNO_3 and NO_3 particles according to the equilibrium relationship between the two species. This equilibrium is a function of ambient temperature and relative humidity. Moreover, the formation of nitrate particles *strongly* depends on availability of NH_3 to form ammonium nitrate, as shown in Figure (taken from CALPUFF courses given by TRC). In Figure 5, the graph on the left[1] shows that with 1 ppb of available ammonia and fixed temperature and humidity (for example, 275 K and 80% humidity), only 50% of the total nitrate forms particulate matter. When the available ammonia is increased to 2 ppb, as shown in the graph on the right, as much as 80% of the total nitrate is in the particulate form. Figure 5 also shows that colder temperatures and higher relative humidity significantly favor nitrate formation and vice versa.

[1] A larger image of the left panel appears in Figure 2.

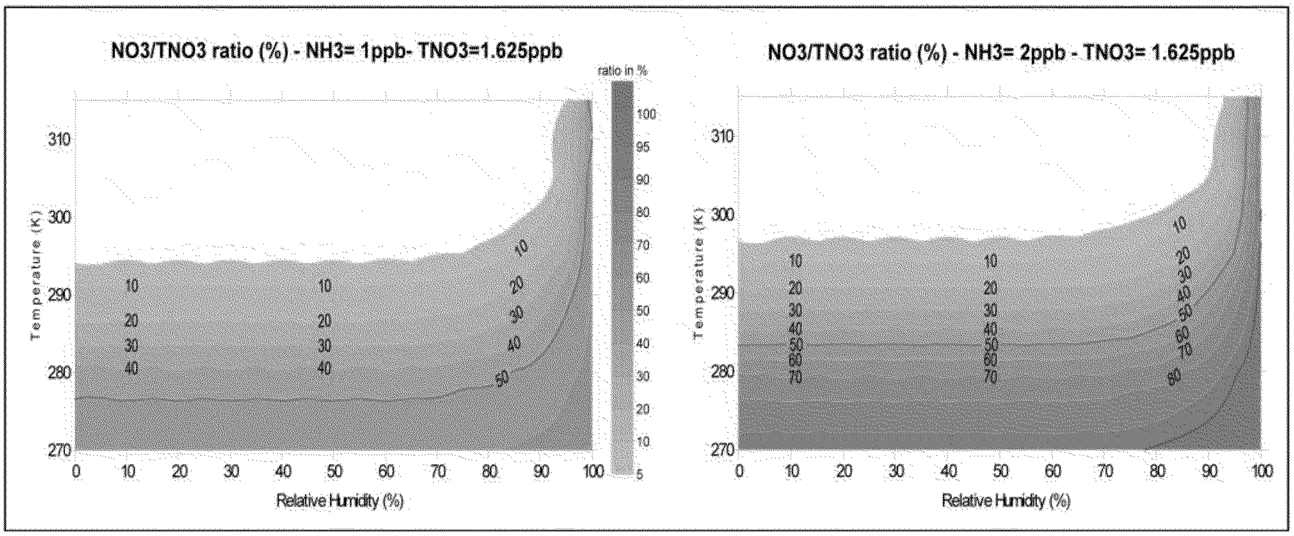


Figure 5. NO_3/HNO_3 Equilibrium Dependency on Temperature and Humidity.

A summary of the conditions affecting nitrate formation are listed below:

- Colder temperature and higher relative humidity create favorable conditions to form nitrate particulate matter, and therefore more ammonium nitrate is formed;
- Warm temperatures and lower relative humidity create less favorable conditions to form nitrate particulate matter, and therefore less ammonium nitrate is formed;
- Sulfate preferentially scavenges ammonia over nitrates. In areas where sulfate concentrations are high and ambient ammonia concentrations are low, there is less ammonia available to react with nitrate, and therefore less ammonium nitrate is formed.

The effects of temperature and background ammonia concentrations on the nitrate formation are the key to understanding the effects of various NO_x control options. For the reasons discussed above, the periods of low temperatures are the most likely to be sensitive to ammonium nitrate formation.

Sensitivity of CALPUFF Predictions to Ammonia Concentration Input

In an independent analysis, the Colorado Department of Public Health and Environment (CDPHE) performed a sensitivity modeling analysis to explore the effect of the ammonia concentration input to CALPUFF on the predicted visibility impacts for a source with high NO_x emissions relative to SO_2 emissions[2]. The results of the sensitivity modeling are shown in Figure 6. It is noteworthy that the largest sensitivity occurs for ammonia input values between 1 and 0.1 ppb. In that range, the difference in the peak visibility impacts predicted by CALPUFF is slightly more than a factor of 3 between ammonia concentration input values of 1 and 0.1 ppb. This sensitivity analysis shows that the choice of background ammonia is very important in terms of the magnitude of visibility impacts predicted by CALPUFF.

[2] Supplemental BART Analysis: CALPUFF Protocol for Class I Federal Area Visibility Improvement Modeling Analysis (DRAFT), revised June 25, 2010, available at http://www.colorado.gov/airquality/documents/Draft - ColoradoSupplementalBARTAnalysisCALPUFFProtocol -25June2010.pdf .

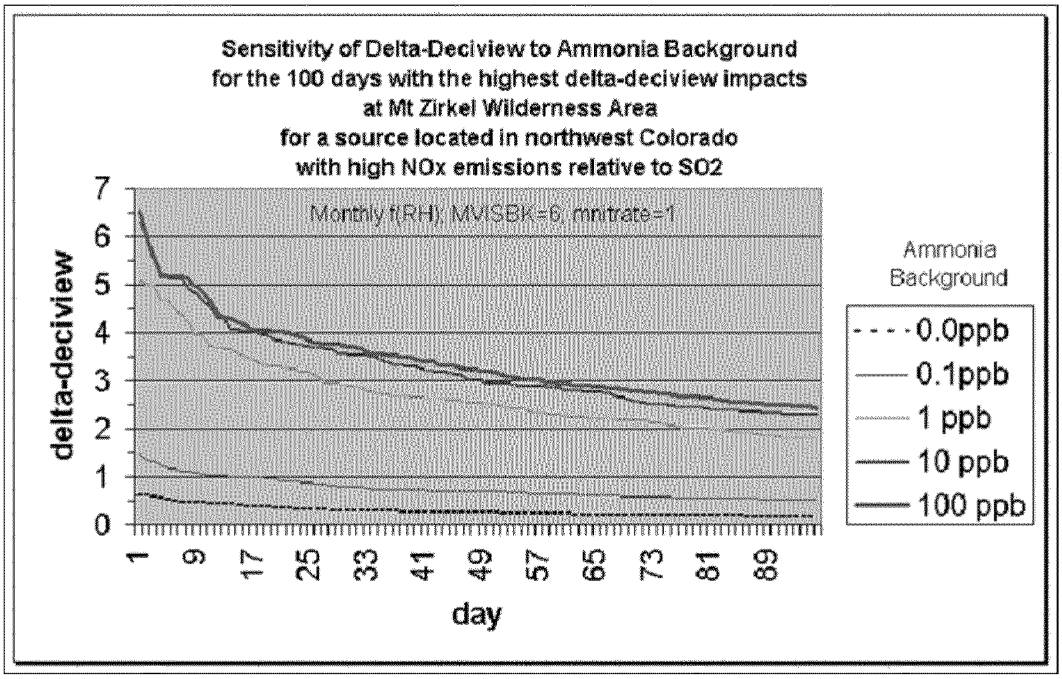


Figure 6. CDPHE Plot of Sensitivity of Visibility Impacts Modeled by CALPUFF for Different Ammonia Backgrounds.

Enhancement to CALPUFF's Model Chemistry

Morris et al.[3] reported that the CALPUFF MESOPUFF II transformation rates were developed using temperatures of 86, 68 and 50°F. Therefore, the 50°F minimum temperature used in development of the model could result in overestimating sulfate and nitrate formation in colder conditions. These investigators found that CALPUFF tended to overpredict nitrate concentrations during winter by a factor of about 3.

A recent independent study that is relevant to the CALPUFF performance for nitrate prediction was performed by Atmospheric and Environmental Research, Inc. (AER) and presented at the October 2009 Air & Waste Management Association Specialty Conference in Raleigh, North Carolina, by Karamchandani et al.[4] ("the KCBB study"). This study presented several improvements to the RIVAD chemistry option in CALPUFF, an alternative treatment that was more amenable to an upgrade than the MESOPUFF II chemistry option. Among other items, the improvements included the replacement of the original CALPUFF secondary particulate matter (PM) modules by newer algorithms that are used in current state-of-the-art regional air quality models such as CMAQ, CMAQ-MADRID, CAMx and REMSAD, and in advanced puff models such as SCICHEM. In addition, the improvements included the incorporation of an aqueous-phase chemistry module based on the treatment in CMAQ. Excerpts from the study papers describing each of the improvements made to CALPUFF in the KCBB study are repeated below.

[3] Morris, R., Steven Lau and Bonyoung Koo, 2005. Evaluation of the CALPUFF Chemistry Algorithms. Presented at A&WMA 98th Annual Conference and Exhibition, June 21-25, 2005 Minneapolis, Minnesota.

[4] Karamchandani, P., S. Chen, R. Bronson, and D. Blewitt, 2009. Development of an Improved Chemistry Version of CALPUFF and Evaluation Using the 1995 SWWYTAF Data Base. Presented at the Air & Waste Management Association Specialty Conference on Guideline on Air Quality Models: Next Generation of Models, October 28-30, 2009, Raleigh, NC.

Gas-Phase Chemistry Improvements

The KCBB study applied a correction to CALPUFF in that the upgraded model was modified to keep track of the puff ozone concentrations between time steps. The authors also updated the oxidation rates of SO_2 and nitrogen dioxide (NO_2) by the hydroxide ion (OH^-) to the rates employed in contemporary photochemical and regional PM models.

Treatment of Inorganic Particulate Matter

The KCBB study scientists noted that the EPA-approved version of CALPUFF currently uses a simple approach to simulate the partitioning of nitrate and sulfate between the gas and particulate phases. In this approach, sulfate is appropriately assumed to be entirely present in the particulate phase, while nitrate is assumed to be formed by the reaction between nitric acid and ammonia.

The KCBB study implemented an additional treatment for inorganic gas-particle equilibrium, based upon an advanced aerosol thermodynamic model referred to as the ISORROPIA model. [5] This model is currently used in several state-of-the-art regional air quality models. With this new module, the improved CALPUFF model developed in the KCBB study includes a treatment of inorganic PM formation that is consistent with the state of the science in air quality modeling, and is critical for the prediction of regional haze due to secondary nitrate formation from NO_x emissions.

Treatment of Organic Particulate Matter

The KCBB study added a treatment for secondary organic aerosols (SOA) that is coupled with the corrected RIVAD scheme described above. The treatment is based on the Model of Aerosol Dynamics, Reaction, Ionization and Dissolution (MADRID)[6,7], which treats SOA formation from both anthropogenic and biogenic volatile organic compound emissions.

Aqueous-Phase Chemistry

The current aqueous-phase formation of sulfate in both CALPUFF's RIVAD and MESOPUFFII schemes is currently approximated with a simplistic treatment that uses an arbitrary pseudo-first order rate in the presence of clouds (0.2% per hour), which is added to the gas-phase rate. There is no explicit treatment of aqueous-phase SO_2 oxidation chemistry. The KCBB study incorporated into CALPUFF a treatment of sulfate formation in clouds that is based on the treatment that is used in EPA's CMAQ model.

CALPUFF Model Evaluation and Sensitivity Tests

The EPA-approved version of CALPUFF and the version with the improved chemistry options were evaluated using the 1995 Southwest Wyoming Technical Air Forum (SWWYTAF) database[8], available from the Wyoming Department of Environmental Quality. The database includes MM5 output for 1995, CALMET and CALPUFF codes and control files, emissions for the Southwest Wyoming Regional

[5] Nenes A., Pilinis C., and Pandis S.N. (1998) Continued Development and Testing of a New Thermodynamic Aerosol Module for Urban and Regional Air Quality Models, *Atmos. Env.*, **33**, 1553-1560.

[6] Zhang, Y., B. Pun, K. Vijayaraghavan, S.-Y. Wu, C. Seigneur, S. Pandis, M. Jacobson, A. Nenes and J.H. Seinfeld, 2004. Development and Application of the Model of Aerosol Dynamics, Reaction, Ionization and Dissolution (MADRID), *J. Geophys. Res.*, 109, D01202, doi:10.1029/2003JD003501.

[7] Pun, B., C. Seigneur, J. Pankow, R. Griffin, and E. Knipping, 2005. An upgraded absorptive secondary organic aerosol partitioning module for three-dimensional air quality applications, 24th Annual American Association for Aerosol Research Conference, Austin, TX, October 17-21, 2005.

[8] Background and database description are available at http://deq.state.wy.us/aqd/prop/2003AppF.pdf .

modeling domain, and selected outputs from the CALPUFF simulations. Several sensitivity studies were also conducted to investigate the effect of background NH_3 concentrations on model predictions of PM nitrate.

Twice-weekly background NH_3 concentrations were provided from monitoring station observations for the Pinedale, Wyoming area. These data were processed to calculate seasonally averaged background NH_3 concentrations for CALPUFF.

Two versions of CALPUFF with different chemistry modules were evaluated with this database:

1. MESOPUFF II chemistry using the Federal Land Managers' Air Quality Related Values Work Group (FLAG) recommended background NH_3 concentration of 1 ppb for arid land. As discussed previously, the MESOPUFF II algorithm is the basis for the currently approved version of CALPUFF that is being used in the BART determination for NGS.

2. Improved CALPUFF RIVAD/ARM3 chemistry using background values of NH_3 concentrations based on measurements in the Pinedale, Wyoming area, as described above.

PM sulfate and nitrate were predicted by the two models and compared with actual measured values obtained at the Bridger Wilderness Area site from the IMPROVE network and the Pinedale site from the Clean Air Status and Trends Network (CASTNET). For the two model configurations evaluated in this study, the results for PM sulfate were very similar, which was expected since the improvements to the CALPUFF chemistry were anticipated to have the most impact on PM nitrate predictions. Therefore, the remaining discussion focuses on the performance of each model with respect to PM nitrate.

The EPA-approved CALPUFF model was found to significantly overpredict PM nitrate concentrations at the two monitoring locations, by a factor of 2 to 3. The performance of the version of CALPUFF with the improved RIVAD chemistry was much better, with an overprediction of about 4% at the Pinedale CASTNET site and of about 28% at the Bridger IMPROVE site.

In an important sensitivity analysis conducted within the KCBB study, both the EPA-approved version of CALPUFF and the improved version were run with a constant ammonia background of 1 ppb.[9] The results were similar to those noted above: the improved CALPUFF predictions were about 2-3 times lower than those from the EPA-approved version of CALPUFF. This result is similar to the results using the seasonal observed values of ammonia, and indicates that the sensitivity of the improved CALPUFF model to the ammonia input value is potentially much less than that of the current EPA-approved model.

Similar sensitivity was noted by Scire et al. in their original work in the SWWYATF study[10], in which they tested seasonally varying levels of background ammonia in CALPUFF (using 0.23 ppb in winter, for example; see Figure 77). The sensitivity modeling for predicting levels of nitrate formation shows very similar results to those reported in the KCBB study.

<u>Availability of a CALPUFF Version 6.4 with Enhanced Chemistry</u>

Recently, TRC implemented the KCBB chemistry improvements into a new version (6.4) of CALPUFF. The following information include excerpts from the "CALPUFF Chemistry Updates Users Guide for API Chemistry Options" issued by TRC on October 25, 2010.

Two chemical transformation module options were recently introduced into the CALPUFF modeling system; they include:

[9] This is a recommendation from the Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Long-Range Transport Modeling, EPA-454/R-98-019, 1998.

[10] Scire, J.S., Z-X Wu, D.G. Strimaitis and G.E. Moore, 2001: The Southwest Wyoming Regional CALPUFF Air Quality Modeling Study – Volume I. Prepared for the Wyoming Dept of Environmental Quality.

For the first module:

- Modification of the existing RIVAD chemical mechanism for the transformation of SO_2 to SO_4 and NO/NO_2 to HNO_3 and NO_3
- Replacement of the MESOPUFF-II CHEMEQ model with the ISORROPIA (Version 1.7) model for inorganic gas-particle equilibrium

  Addition of a new option for aqueous-phase transformation adapted from the RADM cloud implementation in CMAQ/SCICHEM

For the second module:

- Addition of a new option for anthropogenic secondary organic aerosol (SOA) formation based on the CalTech SOA routines implemented in CMAQ-MADRID.

TRC has implemented these modules as options in the current CALPUFF Version 6.4. The first module option is implemented as the 6th CALPUFF chemical transformation option (MCHEM = 6), and the second module is implemented as the 7th CALPUFF chemical transformation option (MCHEM = 7). TRC has also updated the gas-particle equilibrium model for nitrates from ISORROPIA v1.7 to ISORROPIA-II v2.1. Both module options replace the MESOPUFF-II CHEMEQ gas-particle equilibrium model for nitrates with the ISORROPIA-II model. Since total nitrate (TNO3) is partitioned into the gas (HNO3) and particulate (NO3) phases based in part on the ammonia available after preferential scavenging by sulfate, the equilibrium should be determined using the total amount of sulfate and nitrate (due to all sources, background, etc.) present at a particular location and time. This is accomplished using the ammonia-limiting method (ALM) of an updated POSTUTIL postprocessor in the CALPUFF modeling system.

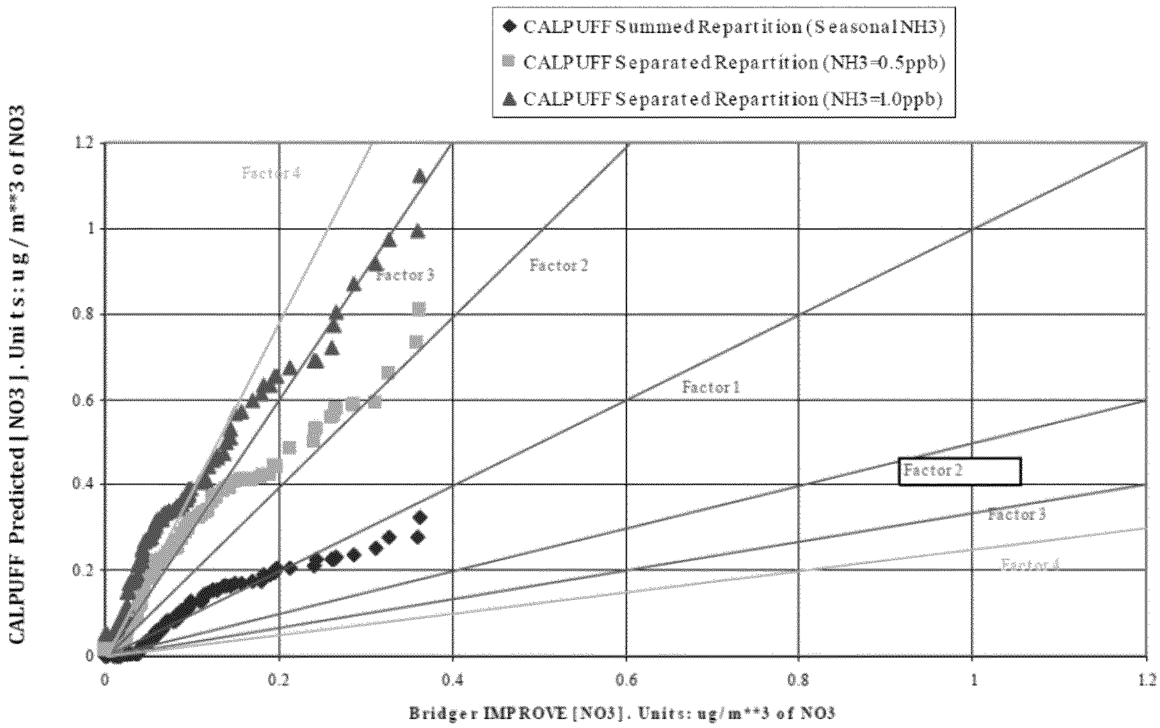


Figure 7. Sensitivity Study of Nitrate Predictions at Bridger Wilderness Area as a Function of Input Ammonia Concentrations to CALPUFF (0.23, 0.5, and 1.0 ppb).

Attachment 9

Exponent®

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facsimile 508-652-8599
www.exponent.com

March 21, 2012

Via E-mail (Bill.Lawson@PacifiCorp.com)

Mr. William Lawson
PacifiCorp Energy
1407 West North Temple, Suite 320
Salt Lake City, Utah 84116

Re: Recommended CALPUFF Version for BART Analyses

Dear Mr.Lawson,

CALPUFF Version 5.8 (v5.8) is the current regulatory version of the CALPUFF model (Scire et al., 2000). The chemical modules in v5.8 of CALPUFF date back to the 1980s. EPA, the Federal Land Managers, and others have acknowledged the deficiencies in the CALPUFF v5.8 chemistry and its tendency to overestimate predicted concentrations of nitrate (Karamchandani et al., 2008, 2009) and potentially to underestimate sulfate from aqueous phase chemical processes in clouds and rainwater (IWAQM (1998)).

Karamchandani et al., (2009) demonstrates overpredictions of nitrate measured at monitoring sites in Wyoming using the v5.8 CALPUFF chemistry by factors of 3-4. Substantial improvements eliminating the overprediction bias of the v5.8 chemistry is found by using the improved ISORROPIA chemistry.

The IWAQM (1998) report acknowledges the lack of aqueous phase chemistry is a substantial limitation of the CALPUFF model:

> "The algorithms currently do not adequately account for the aqueous phase oxidation of sulfur dioxide to sulfate. The aqueous phase chemistry can dominate the formation of sulfate. Therefore, in many applications sulfate is likely to be underestimated."

As a result of work performed for the Electric Power Research Institute (EPRI) and WEST Associates, I very recently presented the results of additional research at the EPA 10th Modeling Conference in RTP, North Carolina describing the improvements in the CALPUFF v6.42 chemistry. This presentation is attached. A summary of the progressive improvements to the model performance with the addition of the new model algorithms is summarized as Figure 1.

As a result of significant improvements made to Version 6.42 (v6.42) series of the CALPUFF model chemistry, it is my recommendation that CALPUFF model v6.42 series code be used for Best Available Retrofit Technology (BART) modeling analyses. This version of the model incorporates state-of-the science aerosol equilibrium chemistry with the addition of the ISOPROPIA chemistry module. In addition, an aqueous phase chemistry model has been added to the model to more properly account for precipitation and wet deposition.

The ISORROPIA gas-particle equilibrium model for nitrate (Nenes et al., 1998; Fountoukis and Nenes, 2007) implemented in CALPUFF v6.42 is widely-used and accepted in the scientific community as is the aqueous phase chemistry model in CALPUFF v6.42 which is based on the EPA CMAQ model aqueous phase chemistry.

In addition to the benefit of significantly improved chemistry, v6.42 of the model represents the latest updated model software with all Model Change Bulletins (MCBs) fully implemented. The EPA version of the model v5.8 contains MCB-A through MCB-D but as indicated on the CALPUFF distribution web site (www.src.com), v5.8 does not contain MCB-E, F, and G and it is therefore out-of-date.

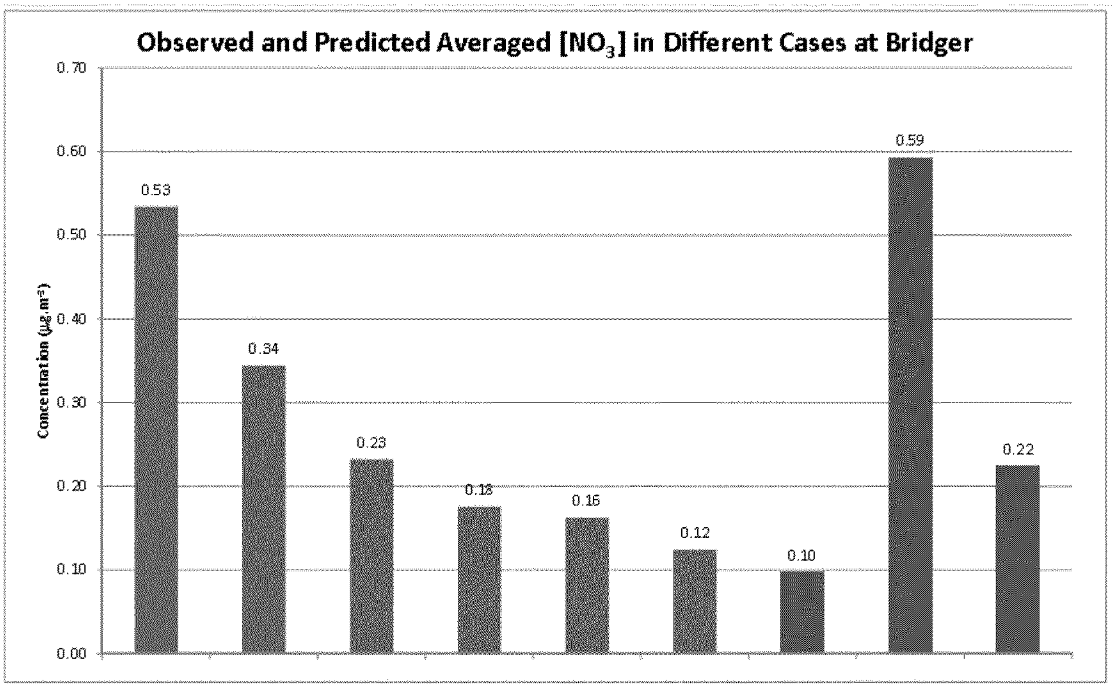
If you have any questions or require additional information, please do not hesitate to contact me at (508) 652-8562 (office) or (508) 808-3821 (mobile) or by e-mail at jscire@exponent.com .

Sincerely,

Joseph S. Scire

Joseph S. Scire, CCM
Principal Scientist

Enc.: Scire presentation EPA 10th Conference, March 15, 2012



Scenario:	Base	Base + ALM	Run A	Run B	Run C	Run C + ALM	Observed	Base2	Run C2
Chemistry:	MESOPUFF II CHEMEQ	MESOPUFF II CHEMEQ/ALM	Modified RIVAD ISORROPIA	Modified RIVAD ISORROPIA	Modified RIVAD ISORROPIA	Modified RIVAD ISORROPIA/ALM		MESOPUFF II CHEMEQ	Modified RIVAD ISORROPIA
Aqueous chem:	No	No	No	Yes	Yes	Yes		No	Yes
Wet dep:	Scav coef.	Scav coef.	Scav coef.	Default LWC	MM5 LWC	MM5 LWC		Scav coef	MM5 LWC
Background NH3	2007 OBS	2007 OBS	2007 OBS	2007 OBS	2007 OBS	2007 OBS		1 ppb	1 ppb

Figure 1. Summary of CALPUFF v6.42 model performance relative to observations of nitrate at the Bridger IMPROVE monitor in Wyoming. Run C is recommended as the model configuration for new regulatory BART analyses (Scire et al., 2012). The Base and Base 2 runs use the v5.8 CALPUFF chemistry and show large overpredictions of nitrate.

References

Fountoukis, C. and A. Nenes, 2007: ISORROPIA II: A Computationally Efficient Aerosol Thermodynamic Equilibrium Model for K+, Ca2+, Mg2+, NH4+, Na+, SO42-, NO3-, Cl-, H2O Aerosols, *Atmos.Chem.Phys* ., **7**, 4639–4659

IWAQM, 1998: Interagency Workgroup on Air Quality Modeling (IWAQM): Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts. U.S. EPA, RTP, NC. EPA-454/R-98-019.

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Karamchandani, P., S.-Y. Chen and R. Balmori, 2009: *Evaluation of Original and Improved Versions of CALPUFF using the 1995 SWWYTAF Data Base*, AER Report CP281-09-01 prepared for API, Washington, DC, October 2009.

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Scire, J.S., F.R. Robe, M.E. Fernau and R.J. Yamartino, 2000: A User's Guide for the CALMET Meteorological Model. (Version 5.0). Earth Tech., Inc. Concord, MA. (Available from http://www.src.com).

Scire, J.S. D.G. Strimaitis and Z-X Wu, 2012: New Developments and Evaluations of the CALPUFF Model. 10th EPA Modeling Conference, RTP, NC. 14-16 March 2012.

Attachment O

New Developments and Evaluations of the CALPUFF Model

Joseph S. Scire, David G. Strimaitis and Zhong-Xiang Wu

Exponent, Inc.
Natick, Massachusetts

March 14-16, 2012
10th Conference of Air Quality Models
RTP, North Carolina

Acknowledgements

- Implementation funded by WEST Associates
- Evaluation co-funded by the Electric Power Research Institute (EPRI) and WEST Associates
- Work performed by CALPUFF model authors while at TRC (Phase I) and now at Exponent, Inc. (Phase II)
- Original implementation of modules conducted by AER (Karamchandani et al., 2008, 2009) under sponsorship of the American Petroleum Institute (API)

Overview of Changes

- **CALPUFF v6.42b Chemical Module Updates**
  - ISORROPIA II (v2.1) used for nitric acid/nitrate aerosol partition
    - ISORROPIA used in Eulerian models such as CMAQ and CAMx
  - Aqueous-phase chemical transformation (adapted from RADM cloud module in CMAQ/SCICHEM)
    - Oxidation of SO_2 in cloud water and rain water
    - V6.42b couples CALPUFF with MM5/WRF liquid water content
    - Tracks location of plume and overlap with cloud layer
  - New RIVAD module tracks depleted O_3 and H_2O_2 in each puff
  - Anthropogenic secondary organic aerosol (SOA) formation (from CalTech SOA routines implemented in CMAQ-MADRID)

Evaluation and Testing of v6.42b

- **SWWYTAF 1995 dataset**
  - Evaluation of actual emissions in SW Wyoming and surrounding area
  - Large-scale, long range transport for a full year (1995)
  - Concentrations at Bridger IMPROVE and Pinedale CASTNet monitors
- **Cumberland Plume Study Dataset (1999)**
  - In-plume/single-event
- **Intercomparison tests with ISORROPIA II in CMAQ v5.0**
  - Over three million Monte Carlo cases evaluated for a wide range of conditions

SWWYTAF Model Evaluation

- **Meteorological Data:**
  - MM5 4-km data
  - CALMET run in no-observations mode for all scenarios
  - 24 vertical layers
- **Total sources: 1776**
  - ♂ Point, area, and boundary sources
  - ♂ Constant annual, monthly variable sources
  - ♂ Time variable (CEM) sources
- **Air Quality Data:**
  - ♂ Bridger IMPROVE and Pinedale CASTNet Sites
  - ♂ NADP Deposition Sites

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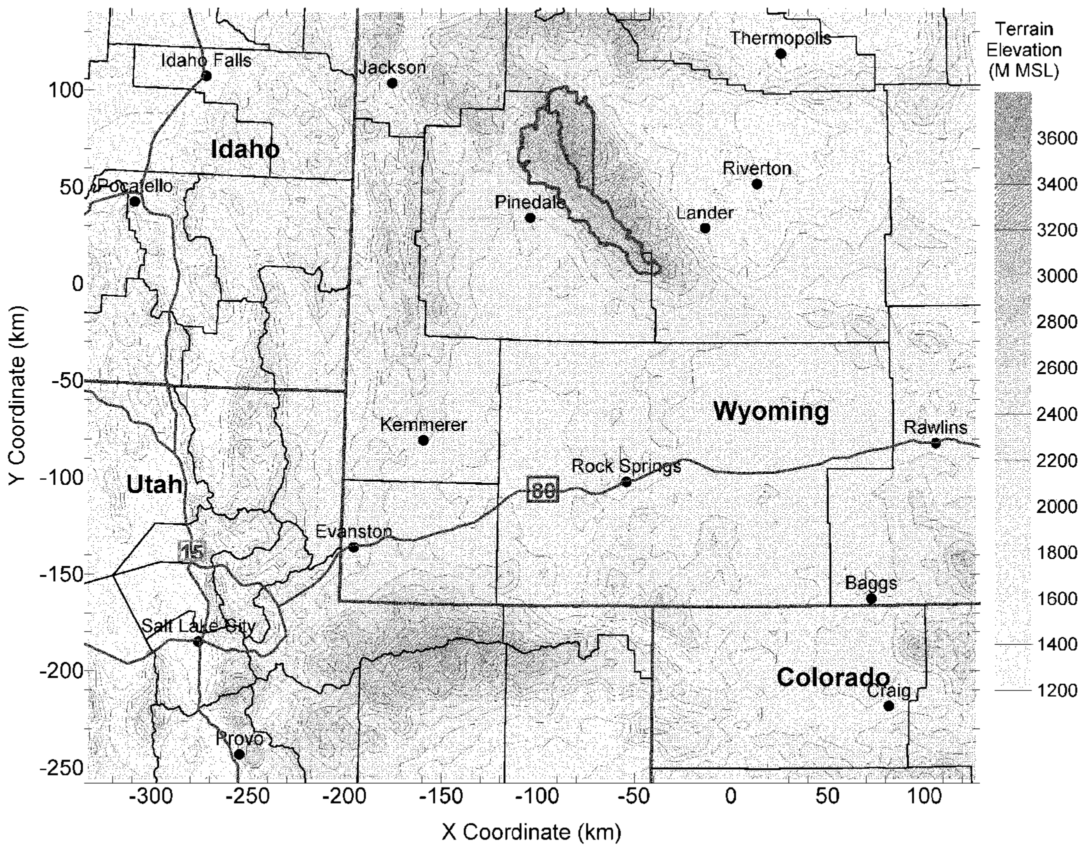
SWWYTAF CALMET Domain



SWWYTAF Scenarios

- **Gas phase chemistry**
  - MESOPUFF II scheme
  - Modified RIVAD (API chemistry)
  - With and without Ammonia Limited Method (ALM) applied in postprocessing step
- **Aerosol chemistry**
  - Original CALPUFF (CHEMEQ) method (Stelson & Seinfeld, 1982)
  - ISORROPIA II (Nenes, Pandis & Pilinis, 1998)
- **Background Ammonia**
  - Constant (1 ppb) background NH_3
  - Seasonally-varying 2007 measured background
- **Wet scavenging/Aqueous phase chemistry**
  - Scavenging coefficient/ No AQ chemistry
  - Aqueous phase chemistry (surrogate and 3D liquid water)

Aqueous-Phase: Cloud Water

- **Cloud Liquid Water Content Option MLWC=0**
  - Surrogate cloud-cover and precipitation data
  - LWC = 0.1 g/kg for non-precipitating clouds
  - LWC = 0.5 g/kg for precipitating clouds
  - In-cloud SO_2 conversion rate apportioned to puff mass by cloud-cover fraction
  - Vertical distribution of cloud water is not addressed
  - Cloud-cover observations are spatially sparse
- **Cloud Liquid Water Content Option MLWC=1**
  - MM5/WRF 3D LWC provides detailed vertical and horizontal resolution
  - CALMET modified to pass 3D LWC data to CALPUFF via CALMET.AUX file
  - CALPUFF uses only LWC that overlaps puff mass distribution

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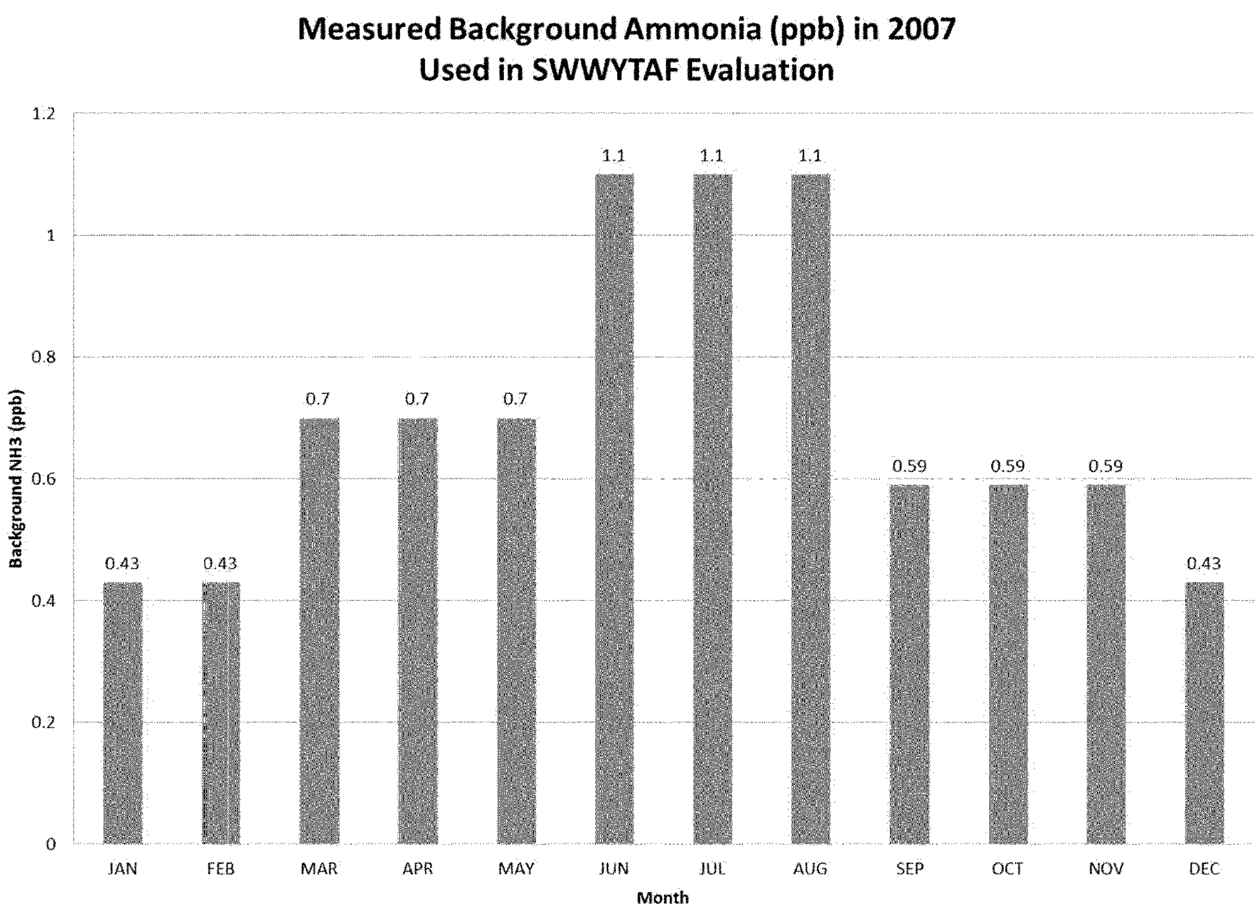
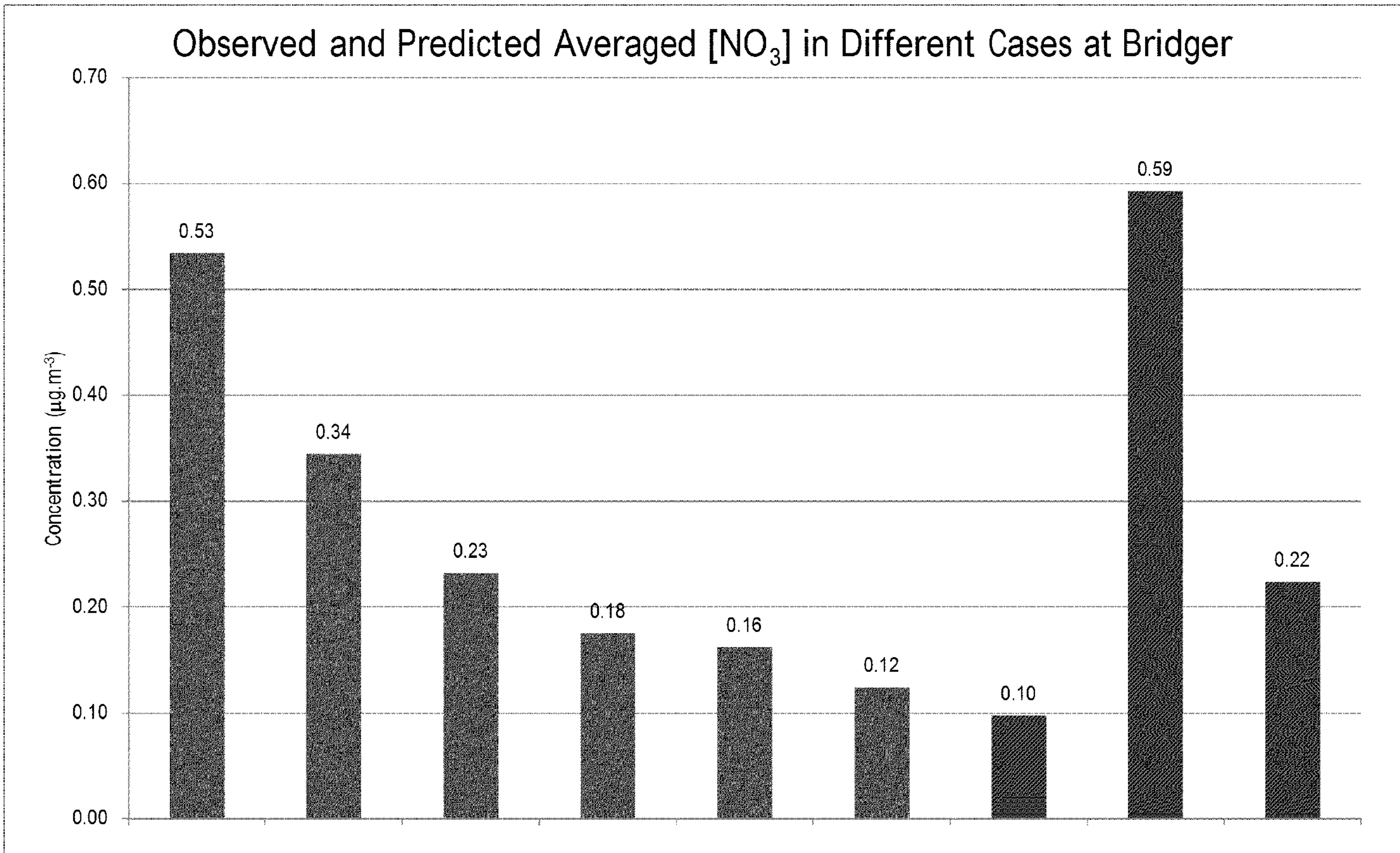
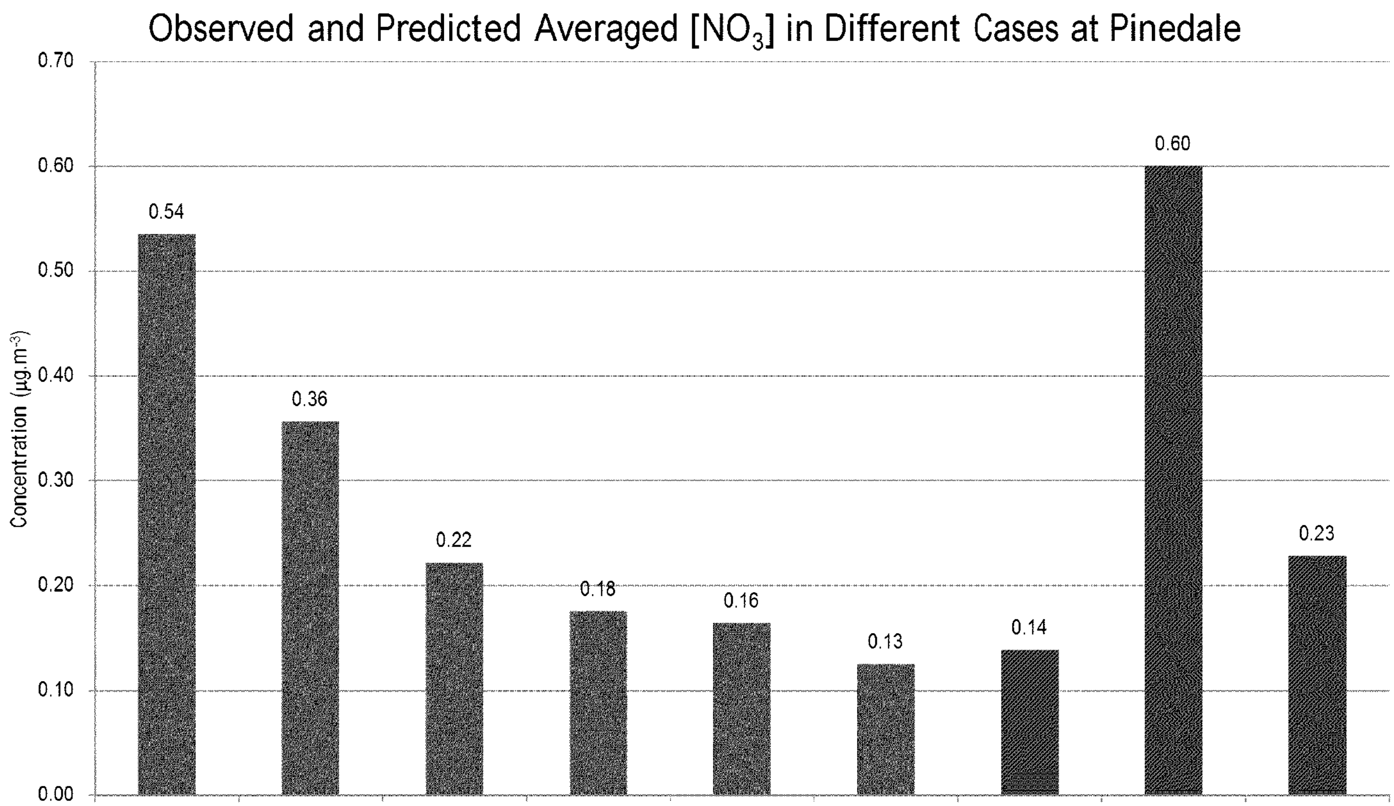




Scenario:	Base	Base + ALM	Run A	Run B	Run C	Run C + ALM	Observed	Base2	Run C2
Chemistry:	MESOPUFF II CHEMEQ	MESOPUFF II CHEMEQ/ALM	Modified RIVAD ISORROPIA	Modified RIVAD ISORROPIA	Modified RIVAD ISORROPIA	Modified RIVAD ISORROPIA/ALM		MESOPUFF II CHEMEQ	Modified RIVAD ISORROPIA
Aqueous chem:	No	No	No	Yes	Yes	Yes		No	Yes
Wet dep:	Scav coef.	Scav coef.	Scav coef.	Default LWC	MM5 LWC	MM5 LWC		Scav coef	MM5 LWC
Background NH3	2007 OBS	2007 OBS	2007 OBS	2007 OBS	2007 OBS	2007 OBS		1 ppb	1 ppb



Scenario:	Base	Base + ALM	Run A	Run B	Run C	Run C + ALM	Observed	Base2	Run C2
Chemistry:	MESOPUFF II CHEMEQ	MESOPUFF II CHEMEQ/ALM	Modified RIVAD ISORROPIA	Modified RIVAD ISORROPIA	Modified RIVAD ISORROPIA	Modified RIVAD ISORROPIA/ALM		MESOPUFF II CHEMEQ	Modified RIVAD ISORROPIA
Aqueous chem:	No	No	No	Yes	Yes	Yes		No	Yes
Wet dep:	Scav coef.	Scav coef.	Scav coef.	Default LWC	MM5 LWC	MM5 LWC		Scav coef	MM5 LWC
Background NH3	2007 OBS	2007 OBS	2007 OBS	2007 OBS	2007 OBS	2007 OBS		1 ppb	1 ppb

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SWWYTAF Summary

- **CALPUFF using constant ammonia with old chemistry overpredicts nitrate by about 4-6x at Bridger and Pinedale, WY**
- **ISORROPIA-v2.1 in CALPUFF-v6.42b substantially improves performance of the model**
- **Use of seasonally-varying ammonia, which shows substantial variability improves performance**
- **Use of aqueous phase chemistry with MM5 3D cloud data produces the overall best results**
- **ALM is important with MESOPUFF II chemistry but results with ISORROPIA are less sensitive to ALM**

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July 1999 Cumberland Plume Study

- **Modules Tested**
  - MCHEM=6: Updated RIVAD implementation with ISORROPIA V2.1 gas-particle phase equilibrium
  - MCHEM=3: Original RIVAD implementation with CHEMEQ gas-particle phase equilibrium
  - MCHEM=1: MESOPUFF II transformation with CHEMEQ gas-particle phase equilibrium
- **Data**
  - Plume chemistry measurements (aerial sampling)
  - Hourly emissions (SO_2, SO_4, NO, NO_2)
  - RADAR wind profiles at the source
  - Tabulated hi-vol data from study report (Tanner et al., 2002)
  - Hourly WMO surface met. reports, 2/day Nashville radiosondes

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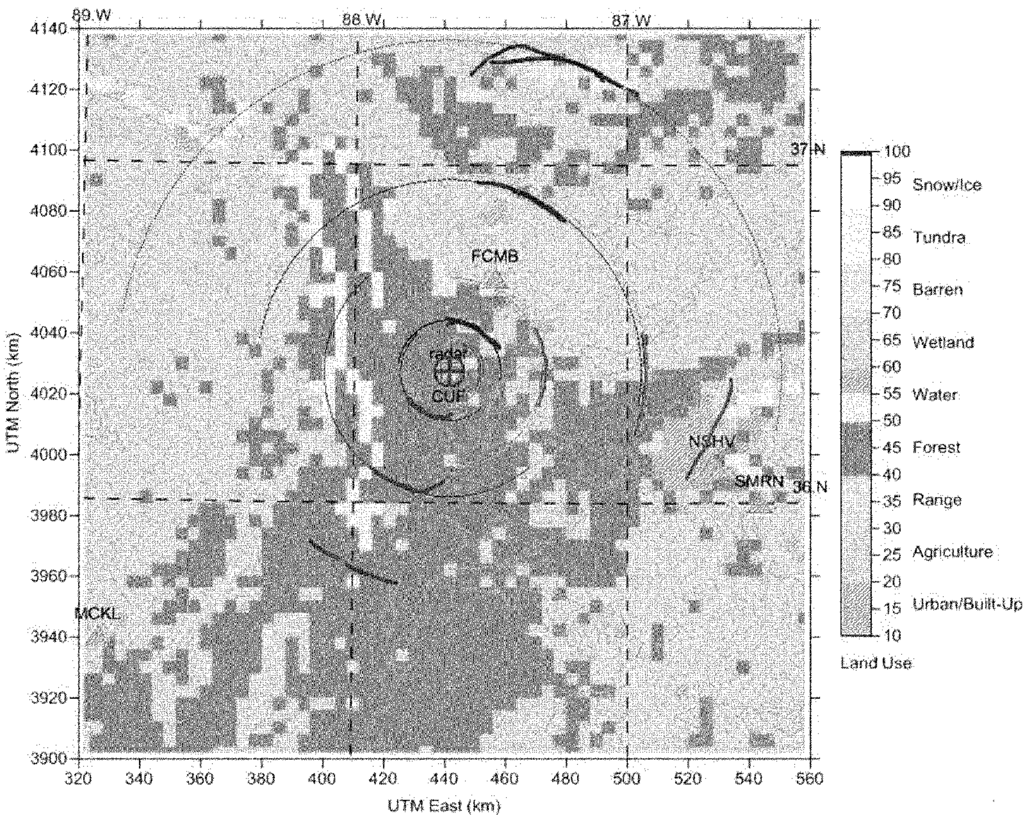
RADAR Wind Profiler at Stack (CUF)
Hourly Surface Meteorology at Triangles, 2/day RAOB Profiles Near NSHV (Nashville)
Aircraft Sampling Locations (blue-grey [E] = July 6; red [SSW] = July 13; green [NNE] = July 15)
High-Resolution CALPUFF Receptors Along Arcs



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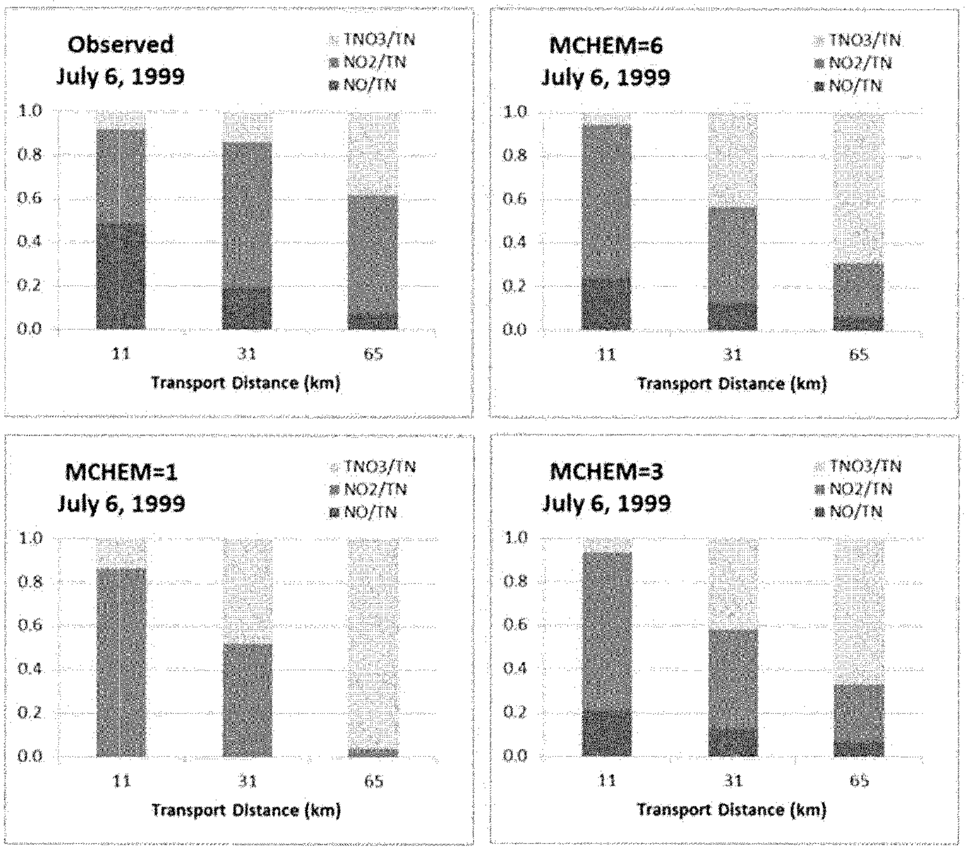
July, 1999 Cumberland Plume Study



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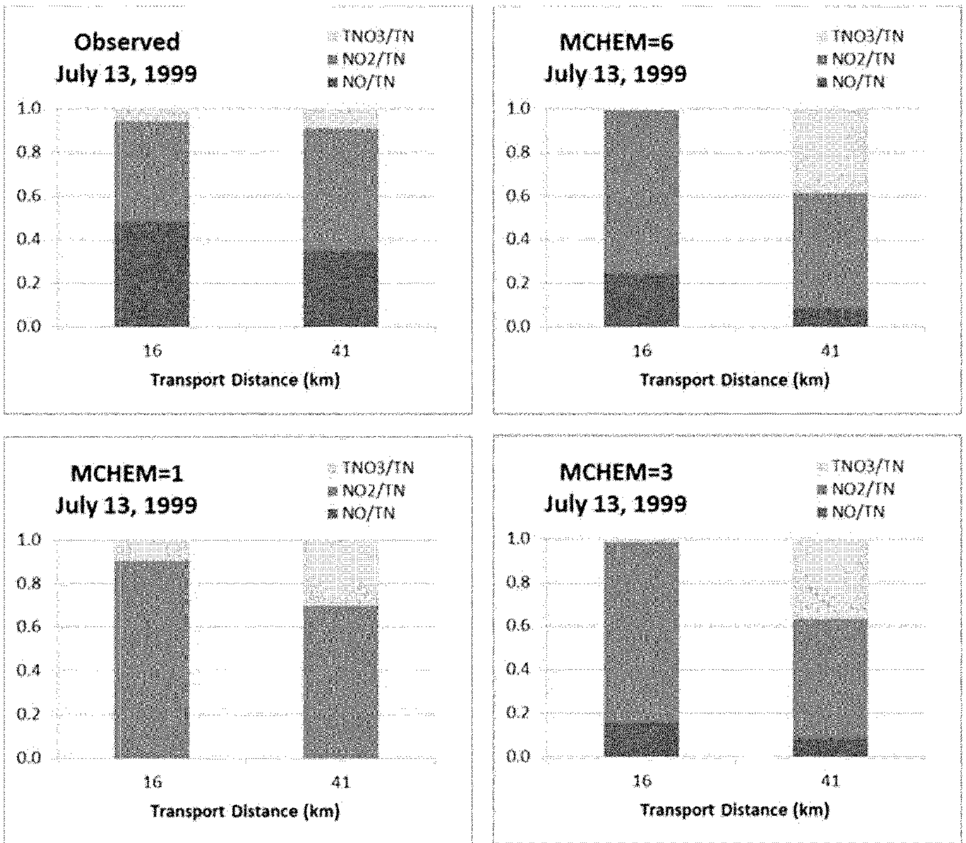
July, 1999 Cumberland Plume Study



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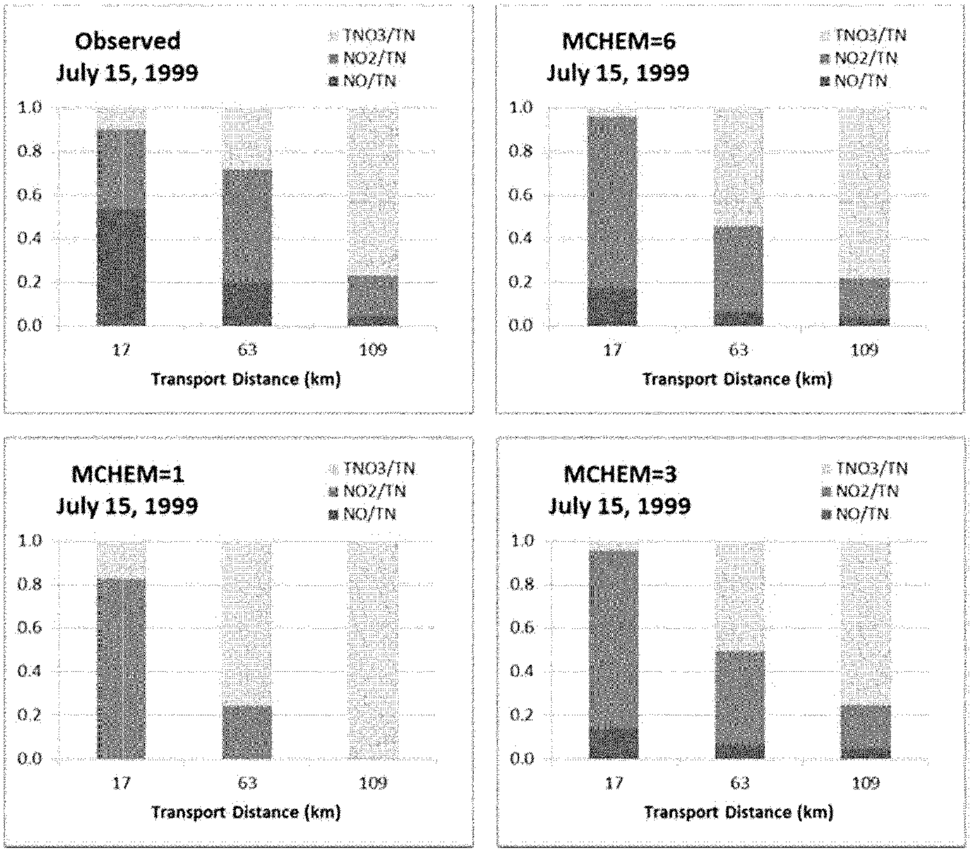
July, 1999 Cumberland Plume Study



Cumberland Plume Summary

- **Revised and original RIVAD implementations are nearly equivalent in modeling the NO_x transformation data for this plume, and improve model performance relative to MESOPUFF II**
- **Updated RIVAD implementation improves modeled SO_4 Conversion Rate**
  - Upper-bound rate on July 15 at 63 km and 109 km = 3.4%/hr (+/-1.2)
  - RIVAD(updated) = 2.7 to 2.9 %/hr (MCHEM=6)
  - RIVAD = 4.2 to 4.4 %/hr (MCHEM=3)
  - MESOPUFF II = 1.8 to 2.1 %/hr (MCHEM=1)
- **Modeled plume nitrate is nearly all HNO_3, with little particulate NO_3, consistent with the partition expected for the indicated meteorological conditions**

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ISORROPIA II in CMAQ v5.0

- **CMAQ v5.0 released February 2012**
- **Subroutines in CALPUFF and CMAQ compared**
  - Bug in array assignment fixed in CMAQ version, and several lines are re-activated
  - New version of ISORROPIA is expected soon
- **Evaluation**
  - Monte Carlo driver compares equilibrium ratio of particulate NO_3 to total nitrate ($TNO_3 = NO_3 + HNO_3$) for range of temperature, relative humidity, and total concentrations of sulfate, nitrate, NH_3
  - Differences in NO_3 / TNO_3 ratios are less than 0.01 in over 99% of the simulations made, and less than 0.1 in all 3 million simulations
  - Compared to CHEMEQ, differences between the two schemes can range up to 100% of the total nitrate, although over 63% of the simulations result in a difference in the NO_3/TNO_3 ratio less than 0.01 and over 84% result in a difference less than 0.10

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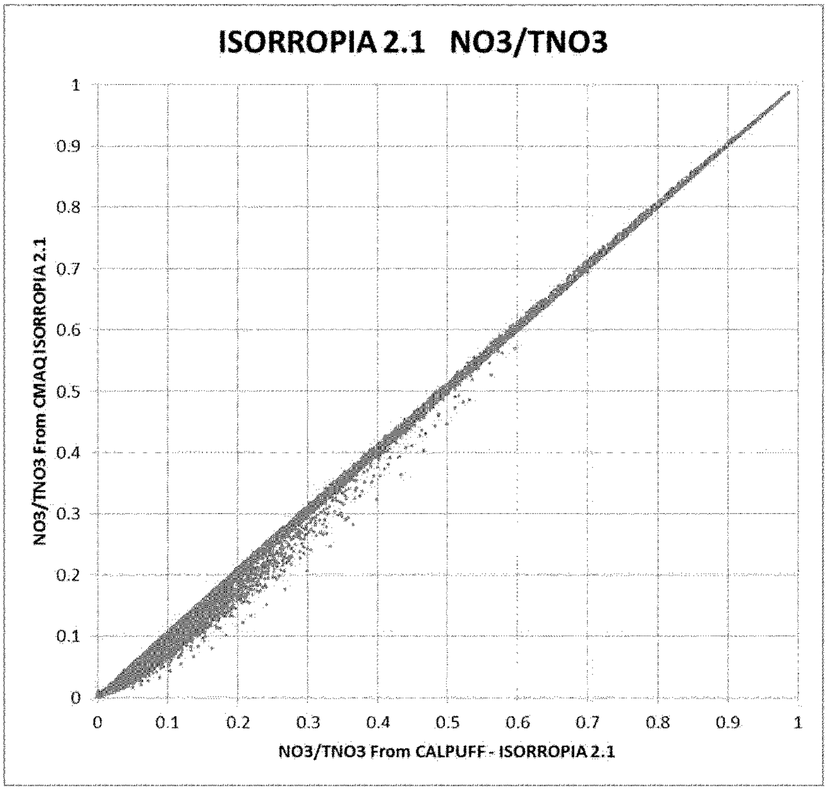
ISORROPIA II in CMAQ and CALPUFF



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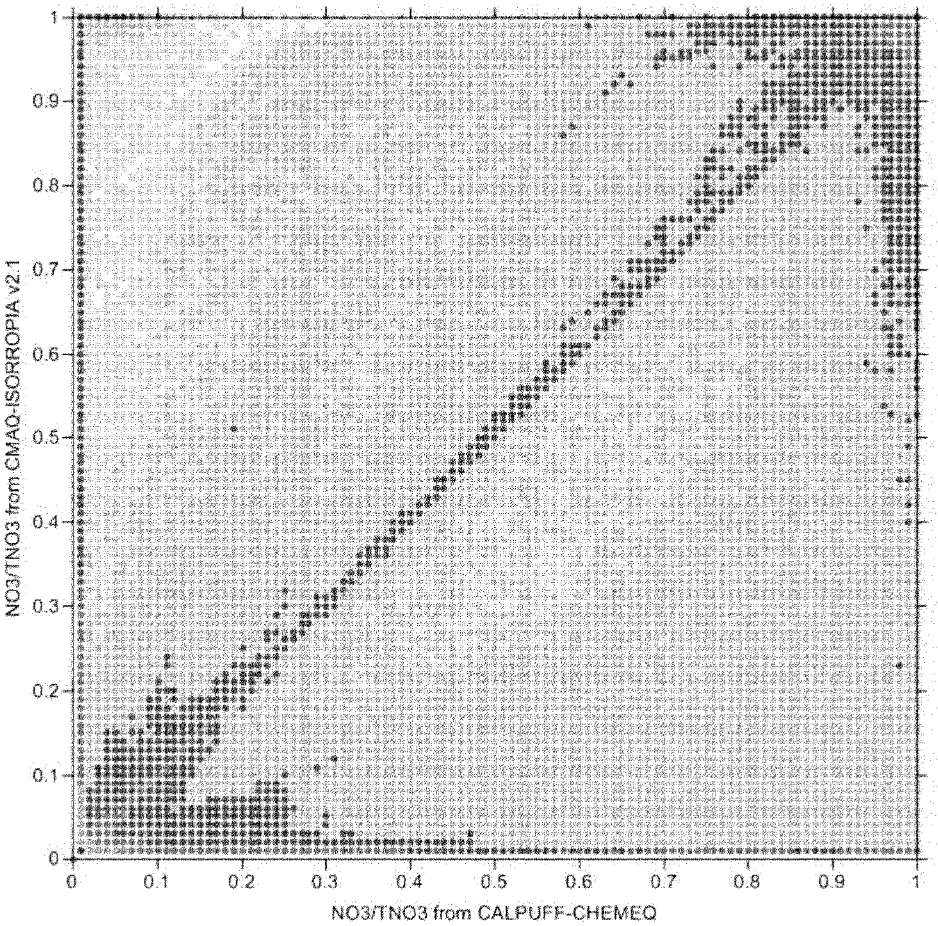
OLD CALPUFF (CHEMEQ) vs CMAQ



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Summary - 1

- **CALPUFF v6.42b includes significant improvements in the treatment of chemical reactions**
  - ISORROPIA II model for inorganic gas-particle equilibrium as in CMAQ
  - Revised gas phase chemical transformation module for SO_2 conversion to sulfate and NO_x conversion to nitric acid and nitrate
  - Aqueous phase oxidation and wet scavenging module adapted from the RADM cloud implementation in CMAQ/SCICHEM, with access to 3D cloud water fields from MM5/WRF
  - New option for anthropogenic secondary organic aerosol (SOA) formation based on the CalTech SOA routines implemented in CMAQ-MADRID

Summary – 2

- **SWWYTAF evaluations with enhanced resolution MM5 meteorological data demonstrates significant improvement in performance over the default FLAG (2010) chemistry options**
- **Large overprediction of average observed nitrate concentrations with the older chemistry mechanism is reduced or eliminated with new chemistry**
- **Cumberland plume simulations indicate O_3 depletion improves the modeled sulfate transformation rate, and both RIVAD module options improve modeled NO_x transformation at large distances**

Conclusions

- **New chemistry modules in v6.42b use well-established algorithms referenced in the referred literature and almost universally accepted in the modeling community as better science**
- **CALPUFF v6.42b is backwardly compatible with v5.8 (after bug fixes are introduced into v5.8). CALPUFF should be adopted as a replacement for v5.8 to allow access to 7 years of optional model improvements, including the new chemistry. Because v6.42b is equivalent to v5.8 when run in the same mode, v6.42b is an equivalent model.**
- **New chemistry can and should be accepted under Section 3.2 of Appendix W**
  - Section 3.2 is designed to allow use of important model enhancements in a timely way on a case-by-case basis, without the 3-5 year wait for formal rulemaking
  - BART rule indicates CALPUFF is acceptable but also allows for alternative models
- **EPA should approve v6.42b on case-by-case basis for use in BART applications**

Attachment 11

TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.
HEADQUARTERS: P.O. BOX 33695 DENVER, COLORADO 80233-0695 303-452-6111

July 2, 2010

Sent via e-mail

Mr. Paul Tourangeau, Director
Air Pollution Control Division
Colorado Department of Public Health and Environment
4300 Cherry Creek Drive South, B Building
Denver, CO 80246-1530

Mr. Doug Lempke
Administrator
Air Quality Control Commission
Colorado Department of Public Health and Environment
4300 Cherry Creek Drive South, EDO-AQCC-A5
Denver, CO 80246-1530

Re: Regional Haze SIP Development Process:
Reopening BART Determinations and Related Modeling

Dear Paul and Doug:

This letter follows up discussions held with Air Pollution Control Division (Division) personnel over the last few months concerning the development of a Regional Haze element of the Colorado State Implementation Plan (SIP). I write today to focus on what we not long ago learned was the Division's intention to ask the Air Quality Control Commission (Commission) to reopen the BART provisions in Regulation 3 concerning the findings the Commission made respecting post-combustion controls for electric generating units (EGUs), and to reopen the BART Determinations that were made in the 2006 – 2008 timeframe. Commission Chair, Barbara Roberts, is copied on this letter because of her invitation to the attendees at the June 17, 2010 Commission meeting. Commissioner Roberts invited stakeholders in the Regional Haze process to provide early comments regarding what should be considered as the Division and the Commission, prepare for the upcoming process concerning the development of the Regional Haze element of the Colorado SIP.

While Tri-State Generation and Transmission Association, Inc. (Tri-State) has significant concerns respecting this reopening of the BART regulations and determinations, those concerns will be addressed separately. This letter is focused solely on the work the Division reports is underway pertaining to the conduct of air quality modeling of BART sources. We assume that Craig Station Units 1 and 2 are included in this modeling exercise. Tri-State requests the

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Division's consideration of the request for consultation contained in this letter, and of the attached White Paper prepared by AECOM. Tri-State respectfully requests that any Division modeling be performed consistent with the recommendations in the AECOM White Paper.

We understand the Division intends to use the CALPUFF model to estimate visibility impacts from existing sources, and to run a series of scenarios in which lower levels of emissions are assumed to correspond to the results of the installation of additional controls. Tri-State would note that there is debate about the appropriateness of the use of CALPUFF for purposes of estimating the impacts of an existing source. This is so because CALPUFF is quite conservative in its estimation of impacts. While the use of CALPUFF modeling may make compelling public policy sense in the context of permitting new sources where one wants to be conservative in terms of the potential impacts of new sources, we question the reasonableness of the use of such over-conservatism to estimate not only the impacts of existing sources, but to also estimate the potential benefits of emission reductions from existing sources because the model similarly would overestimate impacts and, thus provide a skewed view of the benefits of emissions reductions. Nevertheless, without compromising or withdrawing these concerns about the appropriateness of using CALPUFF for this purpose, if the Division intends to perform CALPUFF modeling to evaluate existing Tri-State facilities, in the interest of fairness, due process, and transparency, there should be consultation between the Division and Tri-State as to the assumptions to be used in such CALPUFF modeling in order to minimize areas of disagreement.

We mentioned the following set of issues and concerns to Mike Silverstein on June 9, 2010. We raised these issues and asked if the Division would adjust their modeling work to accommodate these concerns. Having not heard back, and given the aggressive schedule we understand the Division to be pursuing, we wanted to provide this letter for the Division's consideration.

1. We learned in mid-May that a modeling protocol, dated April 15, 2010 had been developed indicating it would be used for BART source-related modeling work. The April protocol was not provided for any public comment, much less for comment from the affected sources to be modeled. In all due respect, taking the position that there was no time for public comment or consultation with the affected sources does not remedy the problems presented. Had there been notice and the opportunity for comment and consultation, it could have avoided or reduced the potential for disagreement over the assumptions to be used in, and thus, the results of such modeling exercises.

2. We were concerned that the April protocol contains statements that modeling will be performed using assumptions with regard to background ammonia levels that

are not reasonable for Northwest Colorado. Specifically, on June 9th we suggested that the capabilities of the new version of the CALPUFF model be utilized to improve the exercise by adjustment of background ammonia concentrations on a seasonal basis. This suggestion was made because we understand this adjustment to be relatively simple. We also indicated that our recollection was that the data from the Mt. Zirkel Study, referenced in a general way in the April protocol, indicate that ammonia concentrations in northwest Colorado are low compared to eastern Colorado and that in the fall, winter, and early spring months, ammonia concentrations in northwest Colorado are extremely low. Accordingly, any CALPUFF modeling that is performed should have background ammonia level assumptions seasonally adjusted to reflect the measured data from the Mt. Zirkel Study concerning northwest Colorado.

3. We are also interested in learning what other assumptions are to be used in this CALPUFF modeling. Important examples of what assumptions we seek to consult about include: What "baseline" operating conditions of the source are used: some artificial 24-hour high value or recent 30-day averages reflecting current conditions? What emissions scenarios are being run and to what emission control levels do they relate? And, to what conditions are modeling scenario runs to be compared: a background of annual average conditions, a background of the average of "20% best" days, or some other condition?

We asked AECOM, which has extensive experience in CALPUFF modeling, to research the topic of ammonia background conditions mentioned above and to provide a report on the subject. An AECOM white paper is enclosed for your consideration. It concludes that the statement in the Division's April protocol indicating use of a 1.0 part-per-billion (ppb) background ammonia level for all 12 months of a year should be modified. The AECOM white paper is based on review of ammonia data near Mt. Zirkel and in Wyoming. The following levels of background ammonia should be used.

- 0.1 ppb during months with snow cover (November – March)
- 0.2 ppb during transition months at the beginning and end of the snow season (April and October)
- 1.0 ppb during the remainder of the year.

In summary, we respectfully ask for the following:

A. Any CALPUFF modeling the Division feels it must undertake should utilize assumptions respecting ammonia background levels based on actual data and consistent with the recommendations of AECOM in the attached white paper and summarized above.

B. Tri-State should be provided an opportunity to consult with the Division staff concerning the balance of the assumptions to be utilized in any CALPUFF modeling to be performed, so that any Tri-State comments can be considered by the Division prior to finalizing any modeling report concerning Tri-State facilities.

If you have questions or wish to discuss these comments, please contact Andy Berger or me at (303) 452-6111

Sincerely,

Barbara A. Walz

Barbara A. Walz
Vice President
Environmental

Enclosure

cc via email w/enc.: Commissioner Barbara Roberts
Doug Lempke
Mike Silverstein
Kirsten King
Will Allison, Esq.

cc: Jim Sanderson
Andy Berger

Selection of Monthly Background Ammonia Concentrations for CALPUFF Modeling in NW Colorado

Jeff Connors and Bob Paine, AECOM

June 12, 2010

Introduction

The Colorado Department of Public Health and Environment (CDPHE) has issued an update to their Best Available Retrofit Technology (BART) modeling protocol, dated April 15, 2010. The BART modeling protocol recommends that CALPUFF is to be used to determine the visibility improvement relating to emission reductions from sources subject to BART.

One of the input parameters to CALPUFF involves the specification of monthly background levels of ammonia. The ammonia concentrations are used in the model to determine the secondary particulate formation of ammonium nitrate from NO_x emissions. We have found that ammonium nitrate formation is particularly important in cold conditions, when seasonal ammonia levels are usually at their lowest. CALPUFF has been shown to significantly overpredict wintertime nitrate formation (Morris et al., 2005) if it uses wintertime ammonia levels that are too high.

It is noteworthy that the CDPHE BART protocol documents a sensitivity study of ammonium nitrate concentrations as a function of background ammonia concentration, and the protocol states that the nitrate modeling results are very sensitive to ammonia background concentrations between 0.1 and 1 ppb, especially in winter Lower predictions of nitrates occur with lower background ammonia values.

The CDPHE protocol states on page 29 that "an annual background ammonia concentration of about 1 ppb or less is probably more reasonable, based on ammonia measurements from the Mt. Zirkel Visibility Study." The "or less" part of this recommendation is very important, especially during the winter season. The protocol does not provide any further discussion about the seasonality of the ammonia background concentration or further discussion of using ammonia concentration values less than 1 ppb. On page 30, the final guidance is to use 1 ppb for ammonia in northwest Colorado for all months. This is probably because at the time of the Mt. Zirkel Study, CALPUFF only had the capability of handling one year-round value for the ammonia background. In light of widespread evidence of seasonal differences (e.g., see attached paper by Molenar et al., 2008) and CALPUFF's current ability to account for monthly variations, the use of one value for the entire year is not justified. The use of annual average values of ammonia concentrations in winter will lead to overpredictions of nitrate concentrations in winter. Since the use of monthly average ammonia values in CALPUFF is very easy to do, we request that CDPHE adjust their CALPUFF modeling procedures for sources in NW Colorado to include the use of monthly ammonia values as described in this report.

The discussion below provides a review of the Mt. Zirkel Study wintertime ammonia concentrations as well as available ammonia concentrations in an adjacent state (Wyoming) to determine the appropriate monthly background ammonia values for CALPUFF BART modeling for sources in NW Colorado.

Available Ammonia Databases

Mount Zirkel Visibility Study

In 1993, the U.S. Forest Service (USFS) certified that occasions existed during which visibility was significantly impaired in the Mount Zirkel Wilderness Area (MZWA). The Mt. Zirkel Visibility Study was commissioned to obtain more information relevant to this certification.

During certain intensive field study periods, the ambient measurements included ammonia measurements at two sites shown in Figure 1 (VORZ near Hayden and BUFZ at Buffalo Gap). The ammonia concentrations were determined by denuder differences (non-denuded NH_4 versus the denuded NH_4 collected on the citric acid filter). The data taken at the two ammonia measurement sites indicated higher ambient ammonia concentration levels at the Hayden VORZ site as compared to the Buffalo Pass site. This is not surprising because, as noted by Watson (2010), there is grazing in the Yampa Valley except during months of snowfall (mid-October through mid-April; see http://www.wrcc.dri.edu/htmlfiles/co/co.sno.html). During the period of snowfall, the absence of anthropogenic ammonia sources (i.e., grazing cattle) lead to very low ammonia concentrations. This phenomenon has also been noted by other researchers (e.g., Kirschner et al., 1999). The Buffalo Pass concentrations are more representative of a regional value than the VORZ values, according to the Study coordinator, Dr. John Watson (2010), because the Hayden VORZ monitor was located close to local sources of ammonia that are not representative of the overall Yampa Valley environment. Therefore, we have proceeded to use only the Buffalo Gap ammonia values in our recommendations for the input to CALPUFF. These values are plotted in Figure 2.

Figure 1 Mount Zirkel Study Measurement Locations

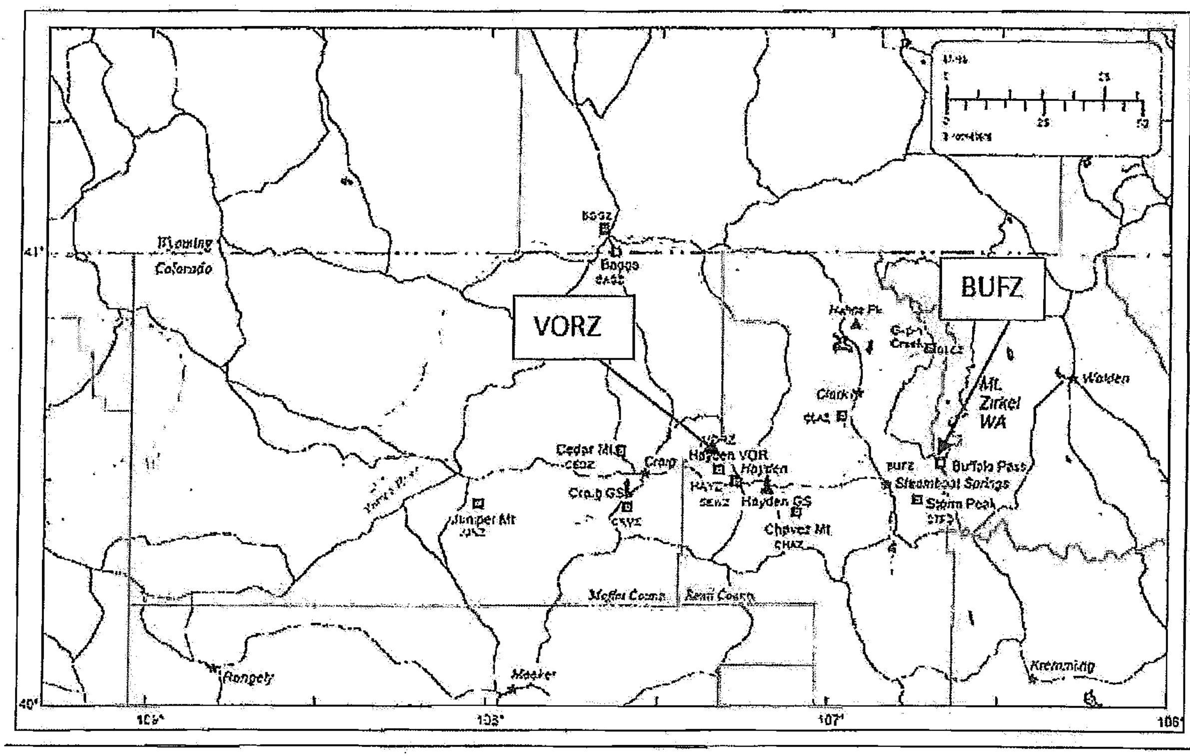
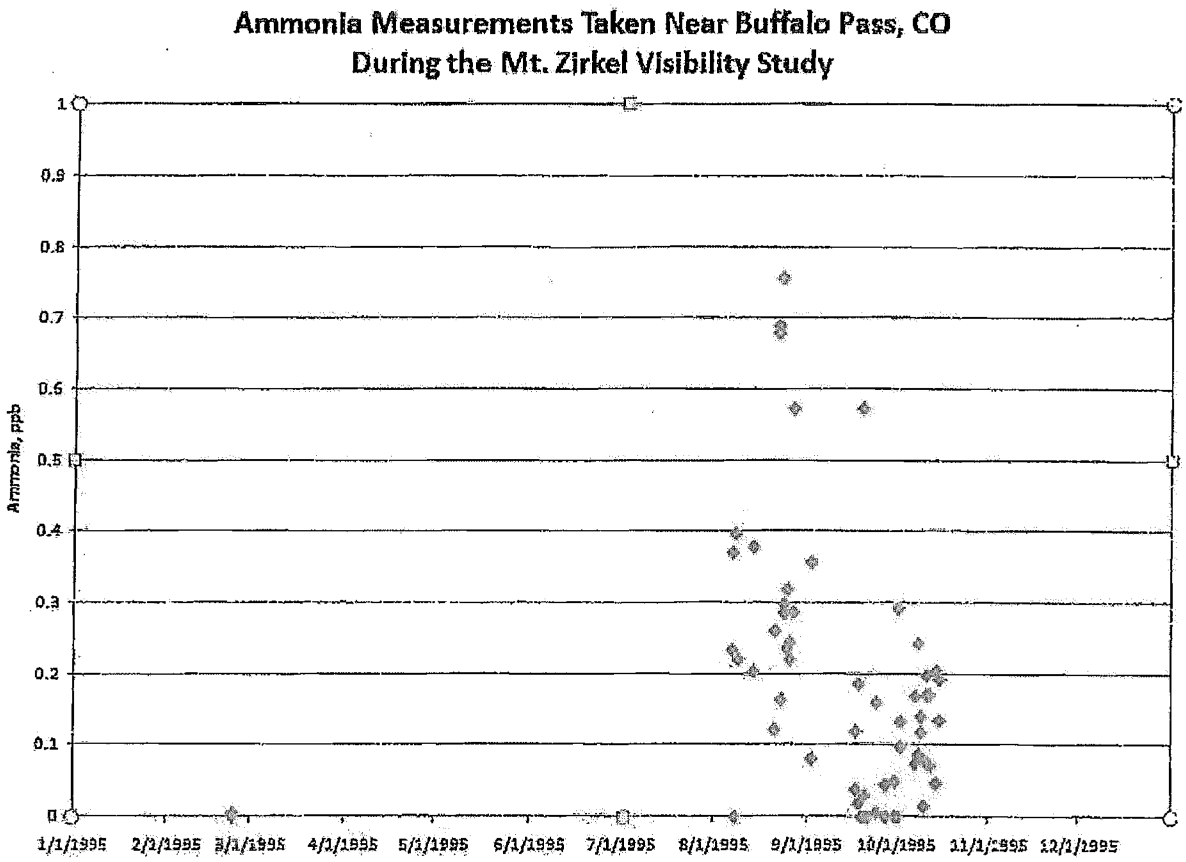


Figure 2 Buffalo Gap Ammonia Concentrations



The Buffalo Gap measurements during the period of snowfall (latter portion of October through mid April) are minimal due to the snow cover, but the concentrations in February indicate very low values (less than or equal to 0.1 ppb). Ammonia concentrations in transition months (April and October) are generally not expected to exceed 0.2 ppb. Ammonia concentrations in the months of May-September can be assigned a value of 1.0 ppb.

Due to the lack of wintertime measurements during the Mt. Zirkel study, another database was reviewed to check on the expected ammonia concentrations during that season.

NH_3 Monitoring in the Upper Green River Basin, Wyoming

A more extensive monitoring program was undertaken in Boulder, WY less than 300 km away from northwestern Colorado (Molenar 2008). Ammonia measurements were taken during this field study every 3 to 4 days using a URG denuder sampler A summary of the ammonia background data over the past three years is provided in Figure 3. The ammonia concentrations observed in Boulder are less than 0.1 ppb during winter, early spring, and late fall. This likely correlated to snow cover which inhibits anthropogenic sources of ammonia such as grazing cattle. The wintertime ammonia values measured in this study are consistent with the choice of 0.1 ppb for the months of November-March for the Yampa Valley sources.

Figure 3 Timeline of Ammonia Concentrations from Boulder, WY (Molenar 2008)

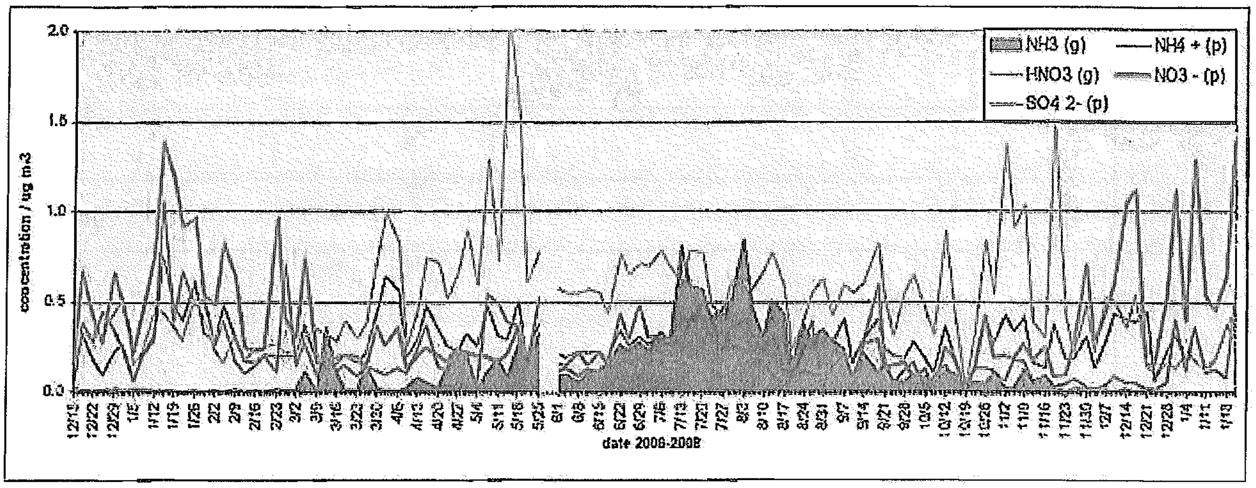
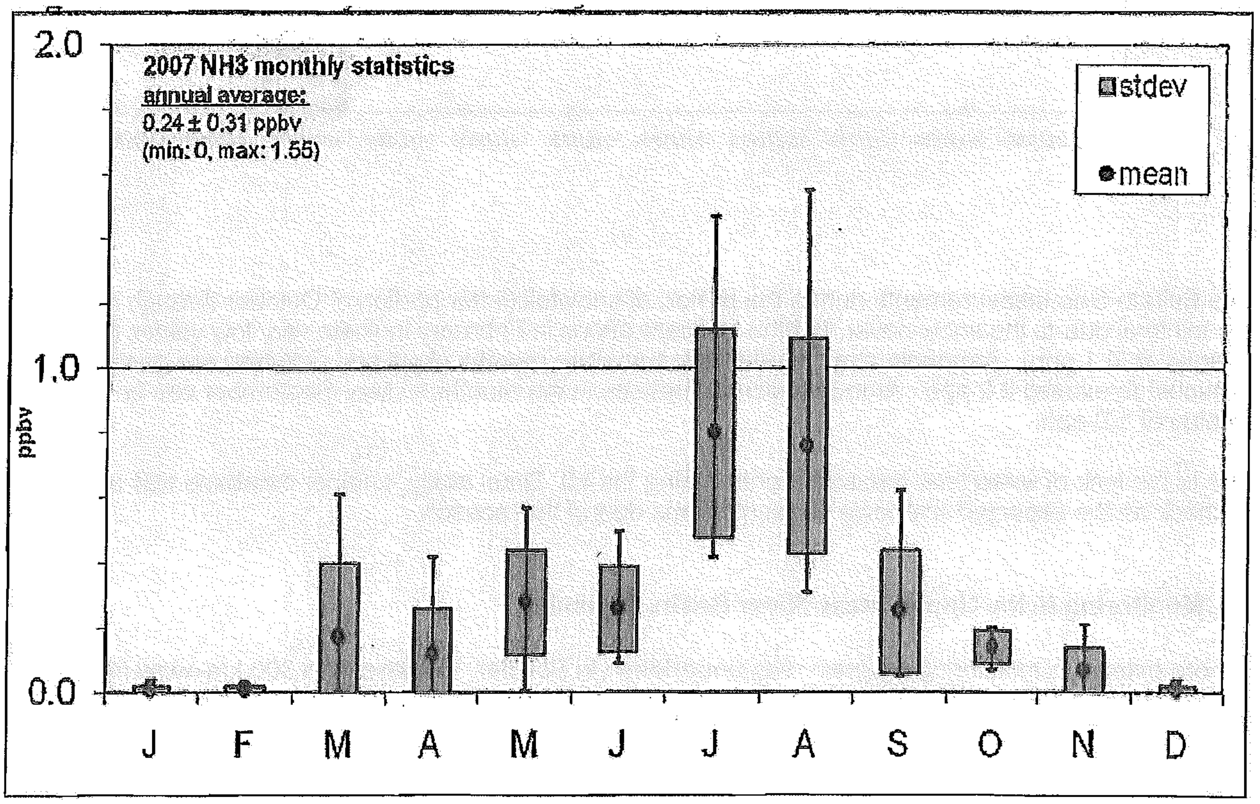


Figure 4 2007 Monthly and Annual NH3 Concentration Data (Molenar 2008)



Conclusions

The ammonia measurements during the Mt. Zirkel study (and confirmed in the Boulder, WY study) which have been plotted in Figures 2-4 suggest a monthly variation of concentrations should be used as input to CALPUFF. The data indicate that the following monthly values would be appropriate:

- 0.1 ppb during months with snow cover (November – March)
- 0.2 ppb during transition months at the beginning and end of the snow season (April and October)
- 1.0 ppb during the remainder of the year

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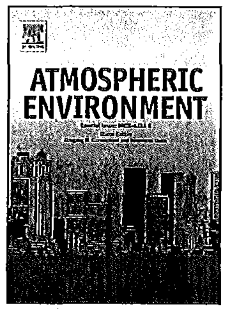
Watson, J. 2010. Personal communication with Mr. Robert Paine

Attachment 12

Accepted Manuscript



Title: Effect of Coal-Fired Power Generation on Visibility in a Nearby National Park

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Effect of Coal-Fired Power Generation on Visibility in a Nearby National Park

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Abstract

The Mohave coal-fired power plant has long been considered a major contributor to visibility impairment in Grand Canyon National Park. The permanent closure of the plant in 2005 provides the opportunity to test this assertion. Although this analysis, based on data from the Interagency Monitoring of Protected Environments (IMPROVE) Aerosol Network, shows that fine sulfate levels in the park dropped following the closure, no statistically significant improvement in visibility resulted. Difference-in-differences estimation was used to control for other influences. This finding has important implications for the methods generally employed to attribute visibility reductions to air pollution sources.

Keywords: Mohave; IMPROVE; Grand Canyon; visibility; CALPUFF

1. Introduction

The Mohave Power Project (MPP) is a large (1,590 MW) coal-fired power plant located 90 miles southeast of Las Vegas in Laughlin, Nevada. Constructed in 1971, the plant was, for some time, the largest emitter of sulfur dioxide in the western United States. In 1998, a group of environmental advocacy organizations sued the plant's owners, alleging that its emissions of sulfur dioxide and particulate matter were in violation of the Clean Air Act. Approximately one year later, the plant was identified as a major cause of visibility impairment in Grand Canyon National Park (GCNP) by the U.S. Environmental Protection Agency (EPA). Upon completion of a multi-year study referred to as Project MOHAVE (Pitchford et al., 1999), the Agency concluded that, although other sources contribute to the visibility reduction, "[because] of the

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quantity of SO_2 emitted from the Mohave Generating Station and its proximity to the Grand Canyon, no other single emissions source is likely to have as great an impact on visibility in the Park."

A few months after this determination, the plant's owners settled the lawsuit and entered into a consent decree which required the plant to reduce SO_2 emissions no later than 2005 (Consent Decree, 1999). Subsequently, the owners estimated that additional emissions controls would cost more than $1 billion and elected to close the plant on December 31, 2005 rather than make such an investment. Over four years have passed since the closure, and we now have the opportunity to determine whether, in the prolonged absence of plant operations, air quality in the Grand Canyon has improved.

2. Literature Review

The link between Mohave emissions and air quality in the Grand Canyon has been studied and debated for over 20 years, resulting in a large body of published research. The most comprehensive study to date, termed Project MOHAVE (Measurement of Haze and Visual Effects) (Pitchford et al., 1999), was performed by the EPA at the request of Congress. This multi-year research effort included two intensive tracer/receptor field experiments, several source emissions simulations and a number of related statistical analyses, all designed to definitively elucidate how MPP operation affected the atmosphere in GCNP.

Despite these considerable efforts, Project MOHAVE's conclusions are ambiguous. Tracer studies revealed that MPP emissions did reach the park, particularly in the summer, when tracer concentrations were recorded above background levels on 90% of the days at the park's western edge. However, there was no evidence linking these elevated concentrations with actual visibility impairment; indeed, "correlation between measured tracer concentration and both particulate sulfur and light extinction were virtually nil" (Pitchford et al., 1999, p. iii). Tracer data also indicated that "primary particles from MPP disperse during transport to GCNP to the extent that though they contribute to visibility impacts they alone would not cause noticeable impairment" (p. v). Overall, the combined results from the tracer studies "strongly suggest[ed] that other sources [than MPP] were primarily responsible for the haze" (p. v).

In contrast to these measurements, pollution transport simulations such as HAZEPUFF

(Latimer, 1993), CALPUFF (Scire et al., 2000), and RAPTD / HOTMAC (Williams et al., 1989) did suggest a negative relationship between MPP emissions and visibility. According to these models, MPP contributed between 8.7% and 42% of measured sulfate on the 90th percentile worst air quality days at the western edge of the Canyon, and 3.1% to 13% of sulfate on the south rim. In terms of visibility, the models showed that MPP increased light extinction by 1.3% to 5.0% at the western edge of the canyon and 0.5% to 2.6% on the south rim. The predicted effect at the 50th percentile was lower in each case, suggesting that MPP impaired visibility most on days when air quality was already quite poor.

Noting the disconnect between the measurements and model predictions, EPA observed that "empirical data (actual field measurements) show poor correlation between the presence of MPP tracer and visibility impairment in the GCNP. Project MOHAVE analysts were unable to find any data to directly corroborate the extreme values calculated by some of the models ..." (Pitchford et al., 1999, p. x). Based on these findings, EPA concluded that MPP was the largest sole contributor to visibility impairment in GCNP. Emissions from large urban areas in California, Arizona and northwestern Mexico were also judged to have contributed significantly (Environmental Protection Agency, 1999).

Subsequent analyses which used CALPUFF to model the transport of MPP emissions to GCNP obtained similar results. A Best Available Retrofit Technology (BART) Assessment[1] conducted for Southern California Edison used CALPUFF to estimate the visibility impact of retrofitting Mohave as a natural gas-fired plant (Paine and Kostrova, 2008). Model results predicted that retrofitting MPP to burn natural gas instead of coal would result in an improvement of approximately 2 deciviews (a standard unit of visibility measure; see below) in the top 2% annual worst air quality days. Additionally, it was estimated that MPP reduced visibility at least .5 dv on approximately 500 days over two years. Another CALPUFF analysis conducted by the State of Nevada found that the 98% percentile improvement would be 2.4 dv and that there would be 186 fewer days annually where the MPP effect would be greater than .5 dv (Nevada Division of Environmental Protection, 2009).

[1] As part of the Regional Haze Rule, EPA requires certain power plants constructed between 1962 and 1977 to install the best-available retrofit technology (BART) in order decrease their emissions of haze-forming pollutants.

Independent reanalyses of the Project MOHAVE tracer data suggest a small or nonexistent Mohave effect. Kuhns et al. (1999) used tracer concentrations during the summer intensive to identify areas which were unaffected by the Mohave plume, and hence only subject to regional changes in sulfate. After controlling for this regional component, they found that MPP was responsible for $7 \mp 3\%$ of the particulate sulfur deposited in the western portion of GCNP; the single largest daily contribution was estimated at $.286 \mp .9\ \mu g/m^3$. Mirabella and Farber (2000) found evidence of a strong regional sulfate component but almost no correlation between local tracer and sulfate concentrations. Eatough et al. (2000) estimated that MPP emissions contributed only 4.3%–5.5% of total sulfate in GCNP; the principal sources of sulfate were surrounding urban areas such as Las Vegas, Los Angeles and the San Joaquin Valley. Later, Eatough et al. (2006) determined that the Los Angeles and Las Vegas urban areas were also the main causes of light extinction in GCNP, and that MPP-associated emissions contributed neglibibly.

Two earlier papers have used a disruption in plant operations to identify MPP's effect on Grand Canyon air quality. First, Murray et al. (1990) examined a seven-month plant closure in 1985 and found no effect on ambient sulfate concentrations in GCNP during the shutdown. They concluded that MPP was responsible for less than 3% of sulfate at the south rim of the canyon. Switzer et al. (1996) expanded on this study by examining monitoring data for the summers of 1985–1987, a period which included both the seven-month shutdown as well as numerous partial shutdowns that occurred when one or both of the plant's two generating units were temporarily offline. By comparing these daily variations in plant operations with simultaneous sulfate measurements taken in GCNP, any link between MPP emissions and GCNP air quality would potentially be cast into greater relief. Despite this added variation, the authors were again unable to detect any statistically significant effect.

There is some evidence that GCNP air quality responded positively to a decrease in emissions from another nearby power plant. Between 1997 and 1999 three scrubbers were installed at the Navajo Generating Station (NGS), a 2,250 MW coal-fired facility located on the eastern edge of GCNP. Analyzing the resulting 90% decrease in emitted SO_2, Green et al. (2005) found that the upper percentiles of the sulfur and light extinction distributions fell following the installation of all three scrubbers. A chi-squared test for independence was used to show that the percentage of winter days exceeding a pre-set threshold for particulate sulfate fell by a statistically significant amount. The authors conclude that reducing NGS emissions decreased winter haze and improved visibility in the park.

3. Model

Since prior research is ambiguous regarding the impact of MPP on GCNP air quality, it is useful reinvestigate this relationship taking advantage of prolonged plant closure and the availability of data to control for weather, background trends in air quality, human activity and other factors which could have affected contemporaneous visibility. A rigorous statistical model is also needed in order to isolate the air quality improvement attributable to emissions reductions.

Consider a two-period model of air quality at a network of regional monitoring sites in the presence of a power plant shutdown. The air quality outcome (light extinction, visibility, pollutant concentration, etc.) at monitoring site $i \in \{1,\ldots,n\}$ in period $t \in \{0,1\}$ is denoted $y_{i,t}$. Air quality at each site and time period is governed by several factors. The first is a regional component R_t which, as the subscript suggests, varies over time but affects all sites equally. Examples of such effects include mesoscale meteorological conditions and pollution transported into the region from large urban areas, as appears to be the case on the Colorado Plateau.

A second component, denoted S_i, captures time-invariant, site-specific effects, which would include elevation and proximity to localized pollution sources whose emissions profiles are relatively constant over time. Finally, emissions from a nearby power plant affect only some of the sites in period 0. Let δ denote this effect, and let $P_{i,0} = 1$ if site i was affected by the plant. The plant closes between the periods 0 and 1, so $P_{i,1} = 0$ for all i. In the treatment effects literature, the group $C := \{i \in \{1,\ldots,n\} : D_{i,0} = 0\}$ is known as the "control" group and $T := \{i \in \{1,\ldots,n\} : D_{i,0} = 1\}$ the "treated" group, and the effect of the plant closure is the treatment effect.

Assuming these components are additive, the air quality outcome at site i in period t is then

$$y_{i,t} = R_t + \delta \cdot P_{i,t} + S_i + v_{i,t}, \tag{1}$$

where $v_{i,t}$ is an error term which is assumed to have zero mean over all i and t. In this model, we only observe $y_{i,t}$ and $P_{i,t}$, and are interested in estimating δ, the effect of the plant operation on the affected sites. Model (1) may be estimated by least squares provided the identifying assumption

$$\mathbb{E}(v_{i,t}|R_t, P_{i,t}, S_i) = 0 \tag{2}$$

holds. In particular, this requires that δ would be zero for the "treated" sites if the closure had not occurred, and that there are no omitted idiosyncratic covariates.

In econometrics, the OLS coefficient $\hat{\delta}$ is known as the difference-in-differences estimator, so-called because the difference in mean outcome between the treated and control groups is computationally identical to the OLS estimator for $\hat{\delta}$ in (1):

$$\hat{\delta} \equiv \overline{\Delta y}_C - \overline{\Delta y}_T, \tag{3}$$

where $\Delta y_i = \Delta R - \delta \cdot P_{i,0} + \Delta v_i$.

This model generalizes to multiple time periods and heterogeneous treatment effects, and additional covariates can (and should) be added to ensure assumption (2) holds. In the air quality arena, this approach has been previously applied to study the effect of pollution regulation on firm location (Millimet and List, 2004; List et al., 2003), particulate matter concentrations on infant mortality (Jayachandran, 2009), air pollution on school absences (Currie et al., 2009), air quality advisories on public transit use (Cutter and Neidell, 2009), and similar policy questions. Previous studies which used spatial or temporal variations in MPP's output as an instrument for GCNP air quality (Murray et al., 1990; Switzer et al., 1996; Kuhns et al., 1999) also employ essentially the same technique, provided the GCNP outcomes are compared with nearby unaffected areas. Conversely, we contend that trend analyses which simply examine air quality over time misidentify the Mohave effect by failing to remove latent regional components and/or control for idiosyncratic effects.

4. Data

We studied the Mohave effect using the above model and a high-frequency, heterogeneous panel of air quality data from the Interagency Monitoring of Protected Visual Environments (IMPROVE) Aerosol Network. The network consists of remote sensing stations located in EPA Class 1 visibility areas, which are primarily national parks and wilderness areas. IMPROVE is EPA's designated data source for measuring air quality under the Regional Haze Rule.[2]

Data are collected every three days, and most of the sites have at least ten years of historical observations available, including three years of data collected after the Mohave closure. The data consist of measurements of sulfate, nitrate, and other aerosol concentrations, as well relative humidity.[3] IMPROVE composites these measurements into a standard index of visibility known as the deciview (dv) (Pitchford and Malm, 1994). The deciview is analogous to the decibel unit of noise measurement; it is approximately linear with respect to perceived changes in visibility, and higher values signify increased degradation. A one-unit decrease in deciviews represents a small but perceptible improvement in visibility. The deciview is the primary metric of the Regional Haze Rule.[4] IMPROVE monitoring sites also include a log which notes maintenance events as well as external anomalies which could perturb the measurements. We used these logs to build an auxiliary panel of anomalous events for control purposes.

Limited censoring was performed on the IMPROVE time series to ensure representativity. We used daily surface wind direction and speed measurements taken at Laughlin/Bullhead City Airport, located 3 miles east of MPP, to isolate days when the wind blew from the south and southwest, directing the Mohave plume towards GCNP. A mid-level wind measurement is preferable to surface wind data when modeling plume transport, but the two should be sufficiently correlated for our purposes. Also, we excluded observations taken on days when the National Weather Service issued warnings concerning dust storm activity in northern Arizona

[2]The Regional Haze Rule (40 CFR 51), promulgated in 1999 by the U.S. EPA to meet Clean Air Act requirements, is designed to improve air quality in general and visibility in particular at 156 national parks and wilderness areas. The Rule obligates the States, in coordination with federal agencies such as the U.S. Forest Service and the National Park Service, to develop and implement plans to improve visibility by 2008.

[3]For lack of a better term, we refer to the IMPROVE data as "daily" even though it is not sampled every day.

[4]In 2006 the IMPROVE Steering Committee adopted a revised algorithm for calculating visibility. The revised estimates were used in this study.

to avoid confounding the visibility measures.

To control for cloudiness and its effect on sulfate formation, daily satellite imagery from NASA's Moderate Resolution Imaging Spectroradiometer (MODIS) program was used to calculate cloud albedo on a $.5 \times .5$-degree (latitude $\times$ longitude) grid. To control for wildfires, a separate MODIS product was used to determine fire activity. This pixel-level data was interpolated over the study area using density estimation to model smoke effects. Finally, we used data on monthly generation at individual power plants in the southwest to examine how regional power generation responded to the Mohave Closure. These data were derived from the U.S. Energy Information Administration's Form EIA-920 database.

5. Analysis

There are three IMPROVE monitoring sites in or near the Grand Canyon. Indian Gardens is 3 km from the south rim at an elevation of 1,166 m, approximately one quarter of the distance from the Colorado River to the upper rim of the canyon. Hance Camp is almost directly above Indian Gardens, on the edge of the south rim at nearly twice the elevation (2,267 m). Meadview overlooks the southern shore of Lake Mead on the western edge of the park. It is 20 km from the mouth of the Grand Canyon and 107 km from MPP.

Project MOHAVE tracer studies suggest areas which were near Mohave but unaffected by its plume Green (1999). Several of these areas have IMPROVE monitoring stations, and they form the basis for comparing air quality outcomes in GCNP. The particular sites used as the control group were Ike's Backbone, Petrified Forest and Queen's Valley. Each site is located on the Colorado Plateau, 100–300 km distant from GCNP. Since these sites are southeast of Mohave, they are unlikely to have been affected by MPP operation, particularly in the summer.

5.1. Descriptive Statistics

Descriptive statistics for the IMPROVE data are shown in Tables 1 (deciviews), 2 (light extinction) and 3 (fine sulfate). The first three rows consider the three GCNP sites, followed by nearby Colorado Plateau sites in rows four through six. The final rows show monitoring data for sites located in Phoenix and east of Southern California (Agua Tibia Wilderness); as transported urban pollution is believed to strongly influence air quality on the plateau, it is wise to examine how these donor areas performed over the same time period. Columns one through four show mean visibility for the entire study period, the pre-closure period 2003–2005, the post-closure period 2006–2008, and the difference in means between the two periods. Comparing the between-group differences in column four is analogous to(3) and hence estimates how the closure altered air quality in GCNP after controlling for other sources of variation.

Average visibility (Table 1) was unchanged at Meadview after the closure; a slight improvement was noted at the upper south rim (Hance Camp); and Indian Gardens worsened slightly. Meanwhile, the control group sites improved by .21–.73 dv. Visibility at sites in Phoenix and Southern California also improved perceptibly post-closure, by 1.22 dv and .69 dv respectively. Similar patterns are seen in light extinction (Table 2). Light extinction fell at every monitoring site in the region compared with before the closure. Large improvements occurred in Phoenix and Southern California, while sites around the Colorado Plateau also improved by lesser amounts. Despite the shutdown, Meadview actually witnessed the least change in light extinction.

Fine sulfate concentrations (Table 3) exhibit a more marked difference between GCNP and surrounding areas. A large drop in SO_4 $\left(-0.11\,\mu g/m^3\right)$ was registered at Meadview, while other sites within the canyon were essentially unchanged. Smaller changes in sulfate concentration were registered elsewhere on the plateau. Finally, sulfate levels in the surrounding urban areas also fell by a significant amount; in particular, the percent improvement in the Southern California region roughly equals that witnessed at Meadview.

Arizona and Southern California are major sources of pollution in the Grand Canyon area. At the same time, they are both distant from and generally downwind of Mohave and hence should not have been affected by the closure. These observations lead us to suspect that visibility improved throughout the region from 2003 to 2008, and that GCNP may have benefited from a drop in transported pollution from surrounding urban areas over that time.

One conclusion of the Project MOHAVE report is that MPP operation was most detrimental to the Grand Canyon on days when air quality was already very poor. If so, the closure effect would be more pronounced at the upper tail of the air quality distribution, for example by decreasing the frequency of days with extremely low visibility. Following Green et al. (2005), Figure 1 shows empirical cumulative distribution plots for fine sulfate at Meadview. For clarity, only the 70th through 99th percentiles are shown. The upper percentiles for fine sulfate at Meadview dropped approximately .2 μg /m^3 following the closure, and extreme events appear to have lessened by varying degrees in each plot. Similar results (not shown) were encountered for Hance Camp and Indian Gardens.

Figure 2 repeats the same plot for the Southern California monitoring station. A similar pattern of improvement emerges even though this site is too far from Mohave to have benefited from the plant closure. This again suggests that regional air quality was improving when the shutdown took place, and underscores the need for a more comprehensive analysis to identify the precise effect of the closure on GCNP.

5.2. Average Effect

Specification (4) is a standard generalization of the two-period difference-in-differences estimator to multiple time periods and sites:

$$y_{i,t} = \beta_0 + \boldsymbol{\beta}_t + \boldsymbol{\beta}_i + \beta_1 \text{FIRE}_{i,t} + \beta_2 \text{CLOUD}_{i,t} + \beta_3 \text{ANOMALY}_{i,t}$$
$$\boldsymbol{\delta} \cdot (\text{SITE}_i \times \text{CLOUSURE}_t) + \boldsymbol{\gamma} \cdot (\text{SITE}_i \times \text{CLOSURE}_t \times \text{SUMMER}_t) + \varepsilon_{i,t} \quad (4)$$

The subscripts i and t index monitoring sites and time (days), respectively. The outcome variable $y_{i,t}$ is deciviews, sulfate or light extinction, as measured by IMPROVE. Vectors $\boldsymbol{\beta}_t$ and $\boldsymbol{\beta}_i$ capture site- and time-level fixed effects, GCNP_i and CLOSURE_t are dummy variables for the Grand Canyon monitoring sites and post-closure days. $\text{FIRE}_{i,t}$ is a unit-less parameter derived from the MODIS fire product. $\text{ANOMALY}_{i,t}$ is an indicator variable equal to one if the site's log noted an anomaly on that day. $\text{CLOUD}_{i,t}$ is cloud albedo, as measured by the MODIS daily high-resolution cloud product. $\varepsilon_{i,t}$ is an error term. Vectors $\boldsymbol{\gamma}$ and $\boldsymbol{\delta}$ represent the net effect of the closure on each GCNP monitoring site in the summer and in the remainder of the year, respectively.

We estimated this specification by multiple regression on a balanced panel of daily data spanning six years (2003–2008, inclusive). Estimation results are reported in Table 4. A Durbin-Watson test showed strong evidence of temporal autocorrelation in the error terms, so the reported standard errors are heteroskedasticity and autocorrelation consistent. The three columns of estimates use sulfate, aerosol light extinction and deciviews as the outcome.

Fire is positively associated with degraded visibility but was not found to be significant. Cloud albedo was also not significant. We suggest that this is because the effect of cloudiness on sulfate formation is largely absorbed by the daily dummy variables. The closure induced drops in sulfate concentrations at all three monitoring sites in the summer. The largest decrease was experienced at Meadview, where sulfate dropped .318 $\mu g/m^3$ on average. The next-largest decrease occurred at Indian Gardens and measured .256 $\mu g/m^3$. Finally, Hance Camp improved by .194 $\mu g/m^3$. The ordering of the coefficients is consistent with the notion that MPP pollution enters GCNP over Meadview, is funneled through the canyon towards Indian Gardens, and has the least impact on the upper rim at Hance Camp. No change was detected in the winter months (October–April) at any location.

Turning to the visibility measures, results show that these reductions in sulfate failed to translate into improved visibility in GCNP. The only statistically significant change in visibility was a 3.346 Mm^{-1} decrease in light extinction at Hance Camp. There was no change in deciviews in the summer or winter at any of the three sites. To see if an increase in some other component could have masked the potential improvement resulting from the closure, we estimated specification (4) for every air quality component used to calculate light extinction and deciviews. We found statistically significant alterations in two components, nitrate and coarse mass. Summer nitrate concentrations fell by approximately .12 $\mu g/m^3$ at Indian Gardens and Hance Camp; no change was detected at Meadview. Coarse mass increased by approximately 2.1 $\mu g/m^3$ at all three sites after the closure.

5.3. Distributional Effect

Discussion of MPP's effect on GCNP is often couched in terms of its effect on the given quantiles of the air quality distribution. The above regressions suggest this effect by isolating periods when wind and season favor poor air quality, but it is also useful to estimate it directly using a quantile regression (Koenker, 2005). Unfortunately, large cross-sectional models such as ours pose theoretical and computational challenges for existing quantile regression techniques Koenker (2004). To alleviate these problems, we estimated a simpler version of specification (4). We used only summer data, and the GCNP sites were pooled into a single treatment group. Month fixed effects were used instead of day fixed effects. The two-step estimator suggested by Canay (2010) was employed to allow for quantile-invariant individual fixed effects.

Regression results are reported in Table 5. The MPP closure resulted in median sulfate levels in GCNP falling by .103 μg /m^3. At the 90th percentile, the change increased to .144 μg /m^3. We found that median light extinction increased by 2.6 Mm^{-1} after the closure, but were unchanged at the 90th percentile. Similarly, overall visibility worsened by .52 dv at the median, but was unchanged at the 90th percentile. Fire had a large, negative effect in air quality in several of the regressions, as did the anomaly indicator variable.

6. Discussion

The Mohave closure decreased fine sulfate concentrations in GCNP. Several different estimations found a statistically significant reduction when compared with nearby sites which not exposed to MPP emissions. The range of our estimates–.10 to .32 μg /m^3 in the summer–corresponds to approximately a 3–10% drop in sulfate, which is in line with Project MOHAVE predictions and earlier estimates of the Mohave sulfate component.

However, we found no corresponding improvement in deciviews or light extinction. This is partially explained by fluctuation in other aerosols masking the drop in sulfate. It is also possible that the sulfate change is too small relative to natural daily variation in visibility conditions to have a significant impact. In the hypothetical case that every component except sulfate remained constant after the closure, analysis of the underlying equations provides some sense of how visibility would have responded. The IMPROVE aerosol light extinction equation is (Pitchford et al., 2007):

$$\begin{aligned} b_{ext} = f_S(RH)\left(2.2 \times SO_4^S + 2.4 \times NO_3^S\right) + f_L(RH)\left(4.8 \times SO_4^L + 5.1 \times NO_3^L\right) + \\ 2.8 \times OM^S + 6.1 \times POM + 10 \times EC + Soil + 1.7 \times f_{SS}(RH) \times SeaSalt + \\ 0.6 \times CM + RS + 0.33 \times NO_2, \quad (5) \end{aligned}$$

where $f(RH)$ is a relative-humidity correction factor, POM measures particulate organic material concentration, EC measures light-absorbing carbon, $Soil$ measures fine soil, CM measures coarse mass, and SO_4 and NO_x measure the relevant oxides. The S and L sub/superscripts denote small- and large-particle concentrations, which for SO_4 are given by $SO_4^L = (SO_4)^2/20$ and $SO_4^S = SO_4 - SO_4^L$. Combining these identities and equation (5) gives

$$\frac{\partial b_{ext}}{\partial SO_4} = 2.2 \cdot f_S(RH) \cdot \left(1 - \frac{SO_4}{10}\right) + 4.8 \cdot f_L(RH) \cdot \frac{SO_4}{10}.$$

With average summer values for Meadview ($f_S(RH) = 1.385; f_L(RH) = 1.267; SO_4 = 1.633$), we have that a $-0.20\ \mu g/m^3$ change in sulfate results in a $-0.71\ Mm^{-1}$ change in light extinction. Using the deciviews formula

$$dv = 10 \times \ln\left(\frac{b_{ext}}{10} + S_R\right), \tag{6}$$

with site-specific Rayleigh scattering constant $S_R = 10\ Mm^{-1}$ for Meadview, this translates to an improvement of roughly .40 dv at an average light extinction level (28.22 Mm^{-1}). Assuming a $-0.7\ \mu g/m^3$ change–much higher than suggested by previous studies, and over twice as large as the greatest change we encountered–gives an expected change of -1.0 dv. Hence, conservatively speaking, we believe it is unlikely that the Mohave closure would have resulted in an visibility improvement in excess of 1 dv (other factors unchanged.)

It is prudent to ask whether any GCNP-specific exogenous change in sulfur could have occurred after the closure; if so, our estimates would be downward-biased. One potential source of SO_2, fire, is controlled for in the model. Another source is power generation. Did a nearby power plant (for example, NGS) increase generation to compensate for the Mohave closure? We examined federal regulatory records of monthly power generation for other plants within 300km of the Grand Canyon before and after the closure and found no indication of such a surge. After taking seasonality into account, regional power generation (excepting Mohave) peaked in 2005, and trended slightly downwards for the remainder of the study period. Additionally, a followup EPA study of the Mohave closure noted that "[most] of the electricity production lost due to the closure of the Mohave Generation Station has been replaced by new natural gas-fired generation, particularly in Nevada" (U.S. Energy Information Administration (EIA), 2009). As the combustion of natural gas releases approximately 1% of the SO_2 of a comparable coal-fired plant (on a MWH basis), there is little possibility that this could have offset the effect of the closure.

Tourism in GCNP is another potential idiosyncratic source of pollution, but again the data do not indicate a countervailing effect. Monthly attendance figures from the National Park Service show that seasonally-adjusted attendance in GCNP was relatively stable from 2003 through 2008. There is no evidence that visits spiked in the years following the MPP closure, as would be required to bias the estimators.

Our results indicate that other components of visibility, in particular coarse mass and nitrate, changed in GCNP after the closure. Soil is known to be the main component of coarse mass in the Grand Canyon (Malm et al., 2007), leading us to hypothesize that dust anomalies in and around GCNP in the years following the closure might caused visibility to worsen. To the extent that these are ignored by the controls we introduced, this constitutes an omitted variable in our model. The creation of a high resolution dust measurement data source would advance our ability to study air quality changes over time in the southwest. Since dust is also a byproduct of driving, specific data on regional vehicle activity is also desirable.

These difficulties are indicative of a larger problem encountered when attempting to conduct inference on a calculated parameter (like deciviews) which it itself a function of many stochastic processes, each governed by a unique set of anthropogenic and natural factors. Achieving identification (in the sense of assumption 2) will generally be much harder than when considering any one parameter in isolation. To the extent that the MPP shutdown mainly affected a single aerosol (SO_4) which has a strong regional component and is relatively stable over time, we are most confident that the sulfate effect is correctly identified.

7. Conclusion

In this paper we studied how operation of the Mohave Power Plant affected air quality in the Grand Canyon. We compared pre- and post-closure visibility in the Canyon and at nearby unaffected sites in order to identify the level of degradation attributable solely to MPP. Net of the prevailing environmental and anthropogenic factors in the region, we found virtually no evidence that the MPP closure improved visibility in the Grand Canyon; or, equivalently, that the plant's operation degraded it. Mean visibility (deciviews) and light extinction in GCNP did not respond to the closure in a statistically significant fashion. Sulfate levels did drop throughout the park, but not by an amount sufficient to induce a perceptible improvement in visibility.

We are thus unable to conclude that the closure improved visibility in the Grand Canyon. Our findings are consistent with, and indeed were predicted by, the results of tracer/receptor analyses performed over the past two decades, which consistently noted low correlation between MPP emissions and GCNP visibility. They stand in contrast to the various atmospheric transport models employed by Project MOHAVE, which predicted that visibility would have improved by 5% or more after the closure.

Since recent applications of CALPUFF (Nevada Division of Environmental Protection, 2009; Paine and Kostrova, 2008) continue to predict that retrofitting MPP will improve visibility in the Grand Canyon, our results raise questions about the reliability of CALPUFF. These concerns are especially pertinent in light of EPA's designation of CALPUFF as the preferred model for assessing the effects of long-range pollution transport on air quality in Class I visibility areas under the Regional Haze Rule.

Acknowledgments

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Outcome: dv	2003–2008 (1)	2003–2005 (2)	2006–2008 (3)	Δ (4)	SD (5)	*N* (6)	Missing (7)
Meadview	8.24	8.23	8.24	0.00	3.06	659	68
Indian Gardens	8.92	8.86	8.96	0.10	3.66	614	113
Hance Camp	6.54	6.61	6.47	−0.14	3.58	695	32
Sycamore Cyn.	10.09	10.22	9.96	−0.26	3.65	675	52
Ike's Backbone	9.36	9.46	9.26	−0.21	3.14	698	29
Phoenix	18.04	18.61	17.40	−1.22	4.39	618	109
So. Cal.	15.90	16.25	15.55	−0.69	5.01	592	135

Table 1: *Descriptive statistics for daily visibility, 2003–2008.*

Outcome: b_{ext}	2003–2008 (1)	2003–2005 (2)	2006–2008 (3)	Δ (4)	SD (5)	*N* (6)	Missing (7)
Meadview	13.93	13.94	13.93	−0.02	8.18	659	68
Indian Gardens	16.41	16.69	16.18	−0.50	14.20	614	113
Hance Camp	11.77	12.38	11.13	−1.25	11.20	695	32
Sycamore Cyn.	20.39	20.97	19.80	−1.17	11.85	675	52
Ike's Backbone	16.86	17.36	16.39	−0.97	9.63	698	29
Phoenix	56.70	61.32	51.47	−9.85	36.80	618	109
So. Cal.	44.24	46.56	41.97	−4.59	27.29	592	135

Table 2: *Descriptive statistics for daily aerosol light extinction, 2003–2008.*

Outcome: SO_4	2003–2008 (1)	2003–2005 (2)	2006–2008 (3)	Δ (4)	SD (5)	*N* (6)	Missing (7)
Meadview	1.17	1.22	1.11	−0.11	0.75	659	68
Indian Gardens	1.02	1.02	1.01	−0.00	0.63	614	113
Hance Camp	0.86	0.87	0.85	−0.01	0.55	695	32
Sycamore Cyn.	0.95	0.97	0.93	−0.04	0.60	675	52
Ike's Backbone	1.14	1.12	1.16	0.04	0.70	698	29
Phoenix	1.59	1.63	1.54	−0.09	0.80	618	109
So. Cal.	2.49	2.60	2.38	−0.22	1.79	592	135

Table 3: *Descriptive statistics for daily fine sulfate, 2003–2008.*

	SO_4	b_{ext}	dv
(Intercept)	1.512***	21.717***	11.073***
	(0.176)	(4.086)	(1.023)
Fire	0.001	0.090	0.014
	(0.002)	(0.069)	(0.012)
Anomaly	−0.173*	13.673	3.313
	(0.087)	(9.975)	(1.897)
Cloud Albedo	−0.001*	0.003	0.001
	(0.000)	(0.006)	(0.002)
Meadview × Closure	−0.004	0.211	0.120
	(0.068)	(0.935)	(0.359)
Meadview × Closure × Summer	−0.318**	0.484	0.118
	(0.116)	(1.566)	(0.490)
Hance Camp × Closure	0.071	0.786	0.458
	(0.046)	(0.865)	(0.351)
Hance Camp × Closure × Summer	−0.194**	−3.346*	−0.918
	(0.073)	(1.675)	(0.489)
Indian Gardens × Closure	0.112**	1.839	0.672*
	(0.042)	(0.975)	(0.339)
Indian Gardens × Closure × Summer	−0.256***	−4.539	−0.939
	(0.074)	(2.871)	(0.530)
adj. R^2	0.790	0.476	0.679
F	21.096	5.719	11.978
$P(>\|F\|)$	0.000	0.000	0.000
N	1601	1556	1556

Significance levels: ***=0.001 **=0.01 *=0.05

Table 4: *Difference-in-differences estimate of the effect of Mohave operation on Grand Canyon air quality.*

Outcome:	SO_4		b_{ext}		dv	
τ	50%	90%	50%	90%	50%	90%
(Intercept)	−0.064	0.894***	−1.991	19.121**	0.243	4.760***
	(0.142)	(0.139)	(1.850)	(7.300)	(0.520)	(0.915)
Fire	0.002	0.004*	0.379***	0.407	0.075***	0.096
	(0.007)	(0.002)	(0.079)	(0.485)	(0.010)	(0.128)
Anomaly	−0.002	−0.324*	3.334	15.452*	1.104	3.335
	(0.177)	(0.163)	(2.494)	(7.438)	(0.884)	(2.492)
Cloud Albedo	0.001***	0.000	0.004	−0.011	0.002	−0.001
	(0.000)	(0.001)	(0.004)	(0.007)	(0.001)	(0.002)
GCNP × Closure	−0.103*	−0.144*	2.597***	0.690	0.519*	0.034
	(0.045)	(0.069)	(0.555)	(1.084)	(0.209)	(0.307)
N	1683	1683	1631	1631	1631	1631

Significance levels: ***=0.001 **=0.01 *=0.05

Table 5: *Difference-in-differences estimate of the effect of Mohave operation on median and 90th percentile air quality in Grand Canyon.*

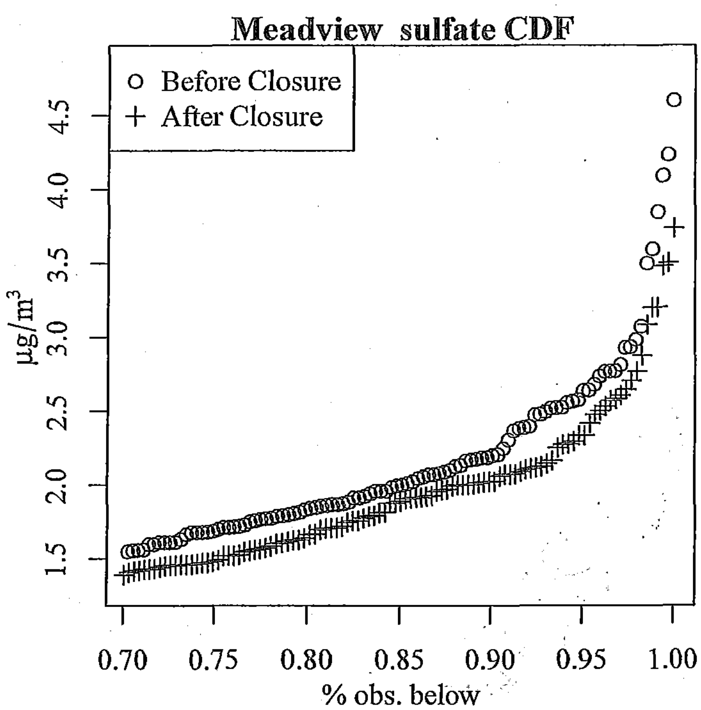


Figure 1: *Empirical cumulative distribution of fine sulfate at Meadview. Plots is of the upper 30 percentiles only.*

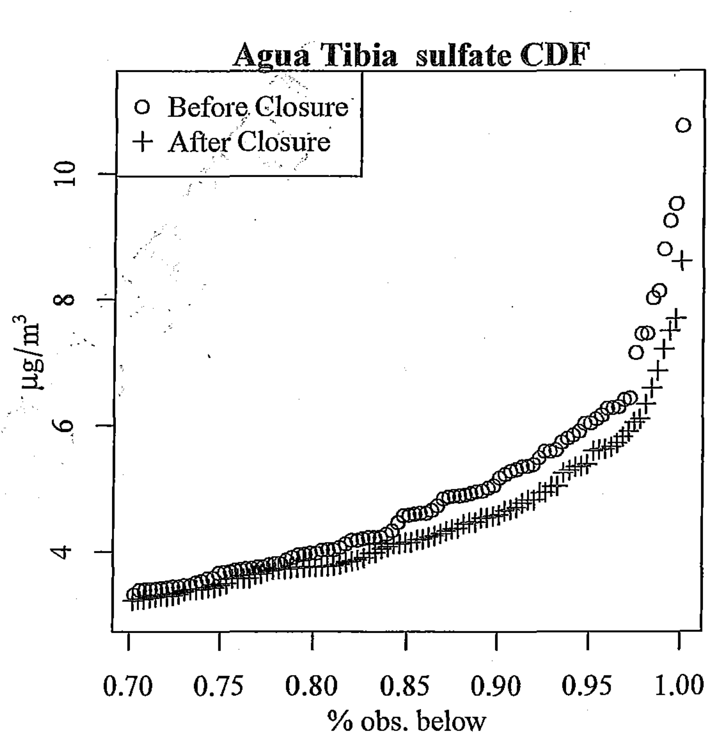


Figure 2: *Empirical cumulative distribution of fine sulfur at Agua Tibia wilderness area. Plot is of the upper 30 percentiles only.*

Attachment 13

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

July 12, 2012 Submitted electronically to www.regulations.gov

Mr. Carl Daly
Director, Air Programs
Environmental Protection Agency Region 8
Mailcode: 8P-AR
1595 Wynkoop Street
Denver, CO 80202-1129

Re: Docket ID No. EPA-R08-OAR-2012-0026
Initial Information Submittal by PacifiCorp

Dear Mr. Daly:

PacifiCorp is providing this initial information [1] in response to EPA 's request regarding comments on its –Proposals in the Alternative‖ for PacifiCorp's Jim Bridger Units 1, 2, 3, and 4 NO_x BART, published in the Federal Register on June 4, 2012. 77 Fed. Reg. 33022, 33053. Specifically, EPA has requested more information regarding what EPA calls the first, second and third proposed approaches in light of the impacts expected as a result of EPA's Federal Implementation Plan (–FIP‖) on PacifiCorp's customers and on the reliability of PacifiCorp's generating system as a whole. In submitting this initial information, it is important to note that PacifiCorp firmly believes the issues of customer impacts and system reliability are not limited to the proposed NO_x BART alternatives for Jim Bridger Units 1, 2, 3 and 4; rather, PacifiCorp believes that in making any determination on a large, multi-jurisdictional system such as PacifiCorp's, the regulating agency must consider the broad scope of the impacts of its decisions on customers and generating system reliability as a whole. This is precisely what the state of Wyoming properly did in establishing its State Implementation Plan (–SIP‖) in this regard. In support of its position, and without waiving any arguments addressing EPA's approach, PacifiCorp provides the following initial information to support EPA's –Third Proposed Approach,‖ as outlined in the June 4, 2012, EPA action, to address the timing of controls at the Jim Bridger units. PacifiCorp believes that the issues raised herein are applicable to the timing of all BART or reasonable progress controls on PacifiCorp's units, whether in Utah, Wyoming, Arizona or Colorado, required to be installed under the Regional Haze program.

[1] PacifiCorp intends to file additional, extensive comments on the EPA's proposed action at a later date.

Because of the Size and Multi-State Nature of its Generation Fleet, PacifiCorp and its Customers are Unreasonably Impacted by the Regional Haze Rules

PacifiCorp provides regulated electric service to more than 1.7 million customers in California, Idaho, Oregon, Utah, Washington and Wyoming with a net system capacity of 10,597 megawatts, operating 75 generating units across the Western U.S. PacifiCorp's diverse generation portfolio includes coal (58% of total owned capacity), natural gas (21% of total capacity), hydroelectric (11% of total capacity), and wind and other resources (10% of total capacity). PacifiCorp is one of the largest owners of rate-regulated renewable generation in the United States (second only to its sister company, MidAmerican Energy Company) with 21% percent of its generation capacity being renewable. PacifiCorp owns and operates 19 coal -fueled generating units in Utah and Wyoming, and owns 100% of Cholla Unit 4, a coal-fueled generating unit in Arizona. In addition, PacifiCorp has an ownership interest in Craig Units 1 and 2 and Hayden Units 1 and 2 in Colorado.

Importantly, for purposes of evaluating EPA's Proposals in the Alternative, more than 80% of PacifiCorp's 6,157 total owned megawatts of coal-fueled generating capacity are BART-eligible. Even without considering the ultimate outcome of EPA's recently proposed action to partially disapprove the Utah Regional Haze SIP, approximately half (more than 3,000 megawatts) of PacifiCorp's coal-fueled generating capacity will be subject to the installation of controls within the next five years. This conclusion is based on EPA's proposed actions to partially approve and partially disapprove Wyoming and Arizona's SIPs and to approve Colorado's SIP. If EPA ultimately attempts to require four additional SCR on PacifiCorp's Utah units as BART controls, which is beyond the NO_x controls already installed or planned for those units under the existing Utah SIP, then the impact on PacifiCorp, its customers, and system reliability will be even more severe.

When considering PacifiCorp's diversified generation portfolio on an energy (as opposed to capacity) basis[2], PacifiCorp's coal-fueled generation fleet serves as the backbone of the system with 66% of the electricity serving customers being coal-fueled. PacifiCorp cannot simply shut these coal units down or replace all of the energy; it is subject to state and federal requirements to provide reliable generation and transmission service on demand. As a result, additional and accelerated costs imposed on coal -fueled plants have a greater cost impact on customers.

[2] The word –energy‖ as used here is intended to mean the amount of electricity actually produced in any given period as opposed to the total ability to produce electricity in that same period. In other words, although a unit may have a rated capacity to produce 100 megawatts of electricity (its capacity), it may only produce 50 megawatts of electricity in a given period (its energy).

<u>EPA's Primary Regional Haze Proposal is Simply Too Much, Too Fast</u>

As evidenced by the emission reduction projects which PacifiCorp has already installed in accordance with the Utah and Wyoming Regional Haze SIPs, PacifiCorp is not opposed to making emission reductions that are cost effective for its customers and that achieve environmental benefits, as required by law. PacifiCorp has undertaken projects to comply with the Utah and Wyoming SIPs at a cost of approximately $1.3 billion (PacifiCorp's share of $1.4 billion of total project costs) between 2005 and 2011. Those projects, in conjunction with projects completed through 2012, have reduced emissions of SO_2 by approximately 58% and emissions of NO_x by approximately 46%, with associated visibility benefits.

Just as modeled visibility improvements associated with PacifiCorp's emission reduction projects do not stop artificially at a state border, EPA's analysis of the impacts of its proposed FIP for a large, multi-state system like PacifiCorp's should not be limited to only those facilities and customers located within Wyoming's borders. EPA's actions impacting large, multi-state systems in one state must also consider the cumulative impacts of all of its actions in all other states that affect the same system. In connection with its proposed FIP in Wyoming, EPA should also consider its proposed partial disapproval of the Utah SIP and the resulting impact on PacifiCorp's four BART-eligible Utah facilities. In addition, EPA Region 8 has already approved the Colorado SIP, which includes major emissions control retrofit requirements for selective catalytic reduction (–SCR‖) and selective non-catalytic reduction (–SNCR‖) and their associated costs at the Craig and Hayden facilities in Colorado. Further, EPA Region 9 recently released a proposed Federal Implementation Plan (–FIP‖) requiring installation of SCR at Cholla Unit 4 within the next five years. In each case, the costs of these incremental environmental controls will be borne by PacifiCorp and its customers, as PacifiCorp's generation fleet costs are allocated on a system-wide basis to customers across all states where it provides retail service. Likewise, in each case, installation of controls on all of these facilities within the prescribed or proposed timeframes takes generation out of PacifiCorp's system for prolonged periods of time to effectuate the construction and tie-in of these controls.

To illustrate the magnitude of the impacts on PacifiCorp's generating system, Table 1 below identifies the units owned (along with ownership share) and operated by PacifiCorp that are impacted by the state SIPs and proposed FIPs. Table 2 includes units in which PacifiCorp has an ownership share but for which it is not the operator, and, therefore, has a financial obligation for controls required by Regional Haze-related requirements.

[Table 1 on next page]

Table 1
Summary of EPA Proposed Incremental NO_x Actions
PacifiCorp Owned and Operated Units

State	Unit	MW	Ownership Share	Proposed NO_x Controls	Installation Requirements
WY	Dave Johnston 1[3]	106	100%	LNB/OFA	SIP – Not required *FIP – July 31, 2018*
WY	Dave Johnston 2[2]	106	100%	LNB/OFA	SIP – Not required *FIP – July 31, 2018*
WY	Dave Johnston 3	220	100%	SNCR	SIP – Not required *FIP – Within 5 years; 2017*
WY	Jim Bridger 1	531	66.66%	SCR	SIP – December 31, 2022 *FIP – 2017 (first proposed approach)* *FIP – 2022 (third proposed approach)*
WY	Jim Bridger 2	527	66.66%	SCR	SIP – December 31, 2021 *FIP – 2017 (first proposed approach)* *FIP – 2021 (third proposed approach)*
WY	Jim Bridger 3	523	66.66%	SCR	SIP – December 31, 2015 *FIP – 2015 (first proposed approach)* *FIP – 2017 (second proposed approach)*
WY	Jim Bridger 4	530	66.66%	SCR	SIP – December 31, 2016 *FIP – 2016 (first proposed approach)* *FIP – 2017 (second proposed approach)*
WY	Naughton Unit 3[4]	330	100%	SCR	SIP – December 31, 2014 *FIP – 2014*

[3] EPA's proposed action on the Wyoming SIP reaches beyond PacifiCorp's BART-eligible units in that state to non-BART-eligible Dave Johnston Units 1 and 2.

[4] While both the Wyoming SIP and the EPA's proposed FIP require installation of SCR and a baghouse at Naughton Unit 3 by the end of 2014, PacifiCorp's economic modeling suggests that it is not cost effective to install the required controls and that a lower cost alternative is conversion of Naughton Unit 3 to natural gas. As a result, PacifiCorp has withdrawn its application for a certificate of public convenience and necessity filed with the Wyoming Public Service Commission and plans to file for the necessary approvals to complete a gas conversion. Significant reductions in emissions of SO_2, NO_x and particulate matter are expected to be achieved as a result of this action.

WY	Wyodak	335	80%	SNCR	SIP – Not required *FIP – Within 5 years; 2017*
UT	Hunter Unit 1	446	94%	TBD	SIP – Not required EPA Action – TBD
UT	Hunter Unit 2	446	60%	TBD	SIP – Not required EPA Action – TBD
UT	Huntington Unit 1	457	100%	TBD	SIP – Not required EPA Action – TBD
UT	Huntington Unit 2	450	100%	TBD	SIP – Not required EPA Action – TBD
	Total impacted megawatts in Utah and Wyoming	5,007			

Table 2
Summary of EPA Proposed Incremental NOx Actions
PacifiCorp Partner Operated Units

State	Unit	MW	Ownership Share	Proposed NO_x Controls	Installation requirements
AZ	Cholla Unit 4	395	100%	SCR	SIP – Not required *FIP – Within 5 years; 2017*
CO	Hayden Unit 1	184	24.46%	SCR	SIP – 2015 EPA Approved
CO	Hayden Unit 2	262	12.60%	SCR	SIP – 2016 EPA Approved
CO	Craig Unit 1	435	19.28%	SNCR	SIP – 2017 EPA Approved
CO	Craig Unit 2	428	19.28%	SCR	SIP – 2016 EPA Approved
	Additional megawatts impacted	1,704			

<u>Accelerated and Incremental Costs Are Significant and Unnecessary To Address Regional Haze</u>

In addition to the expenditures already made between 2005 and 2011 to comply with state-imposed Regional Haze requirements, PacifiCorp also plans to spend approximately $800 million from 2012 through 2022 on emissions reduction projects to meet the emission reduction requirements reflected in the Wyoming and Utah Regional

Haze SIPs. Under either EPA's first or second proposed approaches, PacifiCorp would need to accelerate approximately $260 million of that planned capital expenditures in Wyoming alone and would add approximately $40 million in new capital compliance projects (also in Wyoming). Moreover, all of these accelerated and new costs would be pushed into the pre-2018 timeframe and would result in minimal visibility improvement (as will be explained in detail in PacifiCorp's later comments). Along with the capital costs of these new and accelerated projects will come the costs of operating and maintaining the equipment of approximately $7 million to $10 million annually, as well as ongoing capital expenditures of $4 million to $5 million annually for catalyst replacement projects.

In addition, preliminary estimates of the cost of EPA's recently proposed FIP in Arizona for Cholla Unit 4 is approximately $200 million of incremental capital, along with approximately $2 million to $4 million in levelized annual operating and maintenance and catalyst replacement costs.

Piling on to these costs, the EPA-approved SIP in Colorado results in more than $70 million of incremental capital costs to PacifiCorp, along with approximately $3 million to $5 million in levelized annual operating and maintenance and catalyst replacement costs. Notably, none of the costs quoted above include any added costs of EPA's action in response to the Utah SIP, which according to EPA may involve requirements for retrofits of more units owned by PacifiCorp in that state.

Given the number of facilities operated by PacifiCorp and the facilities in which the company has an ownership interest in and is required to pay costs for the installation of Regional Haze-related controls, accelerated and additional controls under the proposed FIP result in approximately $500 million of additional capital expenditures plus an incremental annual cost of $16-24 million to operate those controls in the next five years. In addition, an EPA proposal for stringent control requirements in Utah (i.e., SCR) within five years would add approximately $750 million in capital expenditures plus approximately $7 million to $9 million annually in operating costs and approximately $4 million annually for catalyst replacement projects. All of these costs will be put on the backs of PacifiCorp and its customers in an extremely short time frame, ironically for a program that was designed to gradually achieve reasonable progress towards the goal of natural visibility conditions by 2064 – 52 years from now. Moreover, EPA's proposed actions in Utah and Wyoming are devoid of the recognition of the significant reductions in emissions already achieved under the Wyoming and Utah Regional Haze SIPs and the significant investment made to obtain those emission reductions.

Compliance with the MATS Adds Incremental Costs and Impacts Available Generation

In addition to the Regional Haze requirements, PacifiCorp's coal-fueled generating fleet, including the BART-eligible units, must accommodate controls for compliance with the

Mercury and Air Toxics Standards (–MATS‖) during the same timeframe. While the scrubbers and baghouses already installed at many of the PacifiCorp facilities pursuant to the Utah and Wyoming Regional Haze SIPs position the company well to comply with the acid gas and non-mercury metals limits under the MATS requirements, additional work will be necessary, particularly at PacifiCorp's Wyoming facilities, to comply with the mercury emission limits by April 2015. Further, PacifiCorp has not yet identified a viable control suite that will allow it to comply with the MATS provisions at the Carbon plant in Utah. As a result, while not finally determined, it is anticipated that Carbon Units 1 and 2 will be required to be shut down in the 2015 timeframe, resulting in the loss[5] of 172 megawatts of generation from PacifiCorp's system. The anticipated loss of this generating resource places additional strain on PacifiCorp's remaining baseload generation and will likely require transmission system modifications to address the resulting lack of generation in that area. Closure of the Carbon plant would also result in an increase in costs to PacifiCorp's customers for removal costs and recovery of plant costs.

PacifiCorp's Customers Cannot Absorb Increasing Environmental Costs, Particularly When Implemented in a Short Period of Time Period

To accommodate, among other cost increases, the costs of the environmental controls already installed on PacifiCorp's coal-fueled generating facilities, PacifiCorp has filed with its utility regulatory authorities annual cases to increase customer rates. PacifiCorp's customers and AARP (among others) have consistently participated in these cases to express concerns regarding increases in electric rates. While EPA may view its proposal to accelerate the installation of controls and require additional controls at PacifiCorp's facilities as just another utility complaining to avoid the consequences of large investments in controls, EPA's proposal has a very real impact on customers.

As Paul Anderson of Mountain Cement Company, a member of the Wyoming Industrial Energy Consumers, testified at the public hearing in Cheyenne on June 26, 2012:

> Our power costs are a significant component of our manufacturing costs. So we're very sensitive to impacts on rates of – of capital investments that are required and other things. This proposal that would speed up the required capital investment is going to have a significant impact on the capital requirements of the utility companies, which then, as a regulated utility, they have the ability to pass on those rates to the rate payers. This will impact every person in the state of Wyoming, from the residential people to the small business operators to the industrial users.[6]

[5] In addition, if the Carbon units are taken out of service and the resulting emissions are eliminated, the state of Utah and EPA should take that into account in determining reasonable progress under the Regional Haze program.

[6] See Transcript of Public Hearing Proceedings from June 26, 2012, available at: http://www.regulations.gov/#!documentDetail;D=EPA -R08-OAR-2012-0026-0035, pages 34-35.

Testimony by the Citizens Utility Board in Oregon has been very pointed on the issue of increasing rates:

> [R]ates for Oregon customers have gone through the roof. . .[t]he primary driver of higher rates has been capital investments. . .It would be helpful if the Company saw capital investments as costs that can be avoided. . .[7]

Additional position statements by the Citizens' Utility Board of Oregon indicate that:

> The double-digit increase that went into effect on January 1 of this year is already proving to be too much for customers to handle. This fact is most easily demonstrated through a review of the number of disconnection notices issued yearly for the last few years. The average number of disconnection notices in 2011 has increased by over 10 percent from previous years on a month-to-month basis. In addition, the average amount of arrearage from residential customers, i.e., the total amount that customers are behind on their bills, has also increased by nearly 25% on a month-to-month basis over previous years.
>
> The primary cause of these rate increases is the massive capital investment MEHC is injecting into PacifiCorp. PacifiCorp's capital investment in coal clean air projects, new wind generation, new transmission lines, and new combined cycle combustion turbines is expected to be in the billions of dollars. . . customers cannot afford this level of investment. [8]

In recent Wyoming Public Service Commission rate proceedings, the AARP expressed the concerns of their 95,000 members in Wyoming about rate hikes:

> This is hardship, unbelievable. [An e-mail] from Mrs. Mary Brandt in Pinedale says. . .this is not the time to raise prices on basics, such as utilities. . .this hike would be just another hardship and discouragement to employers who would be forced to pass this cost on to their customers, many of which are also struggling. . . The point is that the people of

[7] See Oregon Docket UE 246, CUB/100/Jenks-Feighner/pages 12-15, available at: http://edocs.puc.state.or.us/efdocs/HTB/ue246htb152816.pdf

[8] See Opening Comments of the Citizens' Utility Board of Oregon before the Public Utility Commission of Oregon, LC 52, In the Matter of PacifiCorp dba Pacific Power 2011 Integrated Resource Plan, pages 1-2, available at: http://edocs.puc.state.or.us/efdocs/HAC/lc52hac132518.pdf

> Wyoming, and particularly AARP members who are on fixed incomes, and many of them are, simply can't afford to have further rate hikes.[9]

As demonstrated by these groups and individuals, PacifiCorp's customers have already felt the burden of installing emission controls to address Regional Haze; they should not be further burdened by EPA's proposed acceleration of costs, particularly when Wyoming has developed a SIP that takes into consideration the Regional Haze requirements <u>and</u> their impact on electricity consumers.

The very first of the five BART factors stated in the Clean Air Act is ―the costs of compliance.‖ CAA §169A(g)(2). Surely the rate burden placed on electricity customers of a multi-state system like PacifiCorp's as a result of varied actions by EPA in separate states is among the ―costs of compliance‖ Congress intended EPA to consider in the Regional Haze program.

<u>EPA's Primary Proposal Increases Risk to PacifiCorp's System</u>

As a regulated utility, PacifiCorp has a legal obligation to supply reliable electric service at reasonable rates as set by state utility commissions; it also has a legal requirement to supply its customers as much electricity as they want, when they want it. While the installation of emissions controls on multiple units in a short period of time creates substantial challenges from a project management perspective, these challenges are exacerbated by increased risk factors that jeopardize PacifiCorp's ability to meet its underlying utility obligations:

1. <u>Additional Exposure to Market Power Purchases</u> - The compressed tie-in outage schedule proposed by the EPA under the first and second alternatives for the Jim Bridger plant will increase the risk and cost to PacifiCorp's operations and customers by requiring the purchase of substitute power in the electricity markets. Typically, generation owners, including PacifiCorp, conduct periodic maintenance and repairs during long planned outages in the spring and fall ―shoulder months.‖ This is the time when daily loads decline from their summer and winter peaks and substantial amounts of capacity can be removed from service (for maintenance, retrofits, etc.) without degrading system reliability. Environmental retrofit ―tie-ins‖ planned long enough in advance can be incorporated into existing outage schedules (which are also planned long in advance) in order to minimize the time that such generation is not available, particularly because a substantial amount of major environmental retrofit project construction work occurs on site while the unit is in service. However, the ―tie-in‖ outage generally is longer than a typically scheduled maintenance outage, and therefore such outages generally need to be extended by several weeks in order to place the

[9] See In the Matter of the Application of Rocky Mountain Power for Approval of a General Rate Increase in its Retail Electrical Service Rates in Wyoming of $62.8 Million Per Year or 10.4 Percent, Docket No. 2000-405-ER-11 (Record No. 13034), Transcript of Hearing Proceedings before the Public Service Commission of the State of Wyoming.

environmental control equipment into service. When multiple major retrofits occur at many units during a short time frame across a regional system, such outage extensions can materially affect the balance between loads (i.e., electricity demand) and available resources (i.e., electricity supply).

When an imbalance between load and available resources exists, utilities are forced to purchase electricity in the market, if it is available. A multitude of factors can impact electricity market prices, including planned or forced outages, fuel prices, and availability of intermittent resources (i.e., renewables), as well as natural conditions over which entities have no control, such as seasonal temperature variations, wildfires (which, of course, are themselves unexpected and significant contributors to Regional Haze) that may impact transmission facilities, etc. As PacifiCorp is required to take facilities out of service for retrofit equipment tie-ins, it will be forced to make up any load and resource imbalances with power purchases, which have the potential to significantly increase its costs to customers of generation.

2. Management of Planned Outages - The management of planned outages over time also affects the timing of retrofit construction. Generation owners, including PacifiCorp, often find it necessary and advantageous to begin construction sufficiently in advance of a compliance deadline in order to time the retrofit –tie-in‖ outage to coincide with a lengthy planned outage, thus minimizing the amount of additional time the unit is out of service to complete the retrofit. This approach affords generation owners limited flexibility to manage availability of generating units. This limited flexibility, however, is subject to practical limitations of not expending funds too far ahead of compliance deadlines, the required maintenance on individual units, and market drivers such as labor and equipment availability—all while balancing overall outage schedules with market power costs and system reliability considerations. When major control projects are not coordinated with existing outage schedules (such as when EPA unilaterally announces in a FIP a date by which controls must be installed), a unit will be required to either have a second outage to tie-in control equipment, or accelerate or defer the normal planned maintenance schedule. Both of these scenarios increase risk for the unit in question – these risks include added costs, decreased availability potentially during high demand for electricity, and decreased reliability. This is especially true where, as in PacifiCorp's case, a large number of units with multiple control projects must be managed within relatively short periods of time.

Additionally, the joint ownership of many units in the Western U.S. creates an added dynamic whereby changes in planned outages for the tie-in of controls may significantly impact a joint owner's ability to serve its underlying load.

3. Enhanced Risk Associated with Resource Availability - In the Western U.S., the prevalence of hydropower and its typical seasonal output profile means that much more planned outage time occurs in the spring than in the fall. In fact, PacifiCorp historically conducts approximately 90% of its planned outages (measured in MW-days out of service) for fossil units during the spring, when hydropower typically is abundant and

can be relied upon as a firm resource to meet customer demands. While hydro power affords a resource adequacy cushion in average years, drought conditions can reduce this cushion significantly. Not only does hydropower availability influence the resource adequacy cushion, PacifiCorp's analysis of the system impacts associated with past dry years show they can reduce the availability of system resources by as much as 400 available megawatts. In terms of planning for multiple control projects on multiple units required under a FIP in an extremely short time frame, the chance of an inadequate –cushion‖ from hydropower resources (for reasons outside of PacifiCorp's control) only adds to the risk of PacifiCorp being unable to meet its electricity supply obligations or being able to do so at an unfair cost to its customers.

<u>4. Planning for Adequate Generation and Reasonable Costs</u> - PacifiCorp performs load and resource assessments as part of its biennial Integrated Resource Plan (–IRP‖). These assessments focus on load and resource conditions forecasted during the summer peak. Recognizing that the impact of major emission controls retrofit project –tie-in‖ outages would be felt primarily in the Spring months, the IRP Load & Resource balance framework has been extended to those months to provide additional information pertaining to PacifiCorp's planning considerations.

Resource planning requires forecasts of peak hour loads and available resources to meet those loads. The supply/demand balance methodology used in PacifiCorp's IRPs compares peak load (plus a planning reserve margin) against owned and firm resources, including thermal capacity, hydroelectric capacity, renewables and qualifying facilities, demand-side management resources (DSM), and net firm purchases. Although the IRP focuses on July system peak conditions, monthly load and resource projections through 2022 can be constructed using other data that PacifiCorp utilizes for 10-year modeling outlooks.

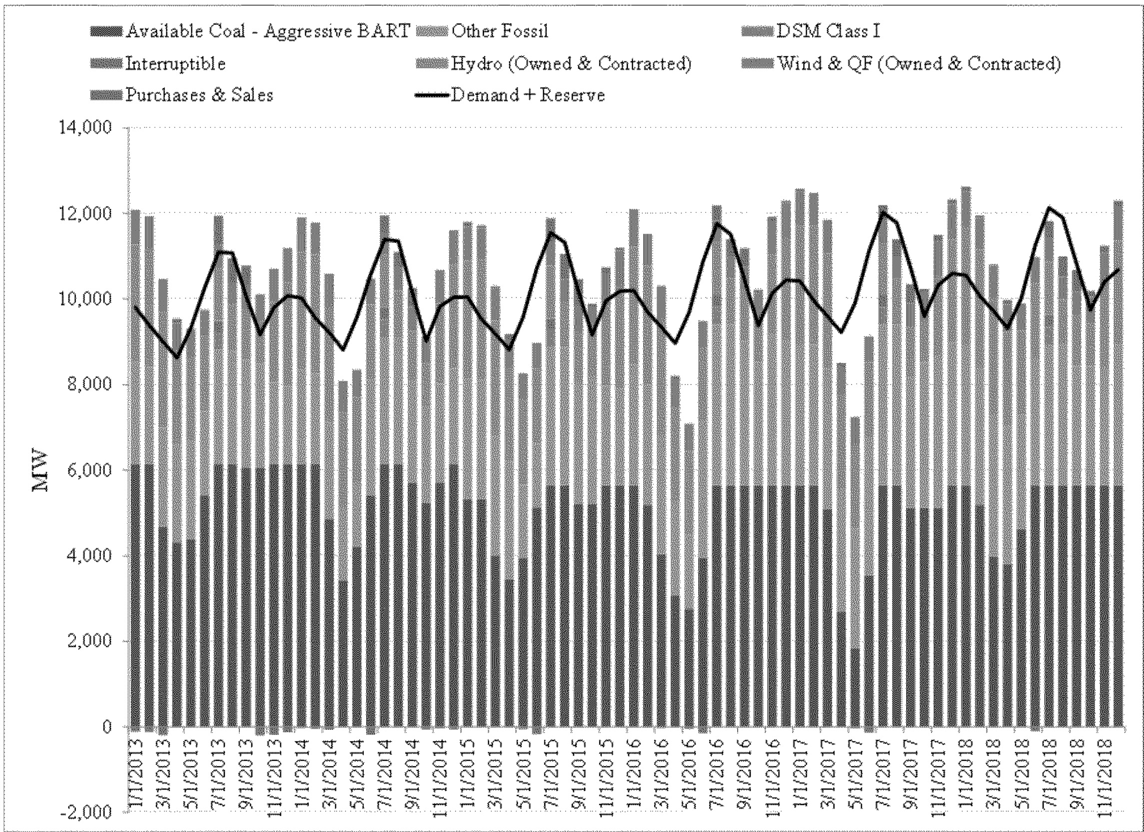
PacifiCorp has examined two scenarios to evaluate the implications of complying with EPA's proposed and prospective actions on Regional Haze proposals throughout the Western U.S., particularly those regions impacting PacifiCorp operations. The scenarios include:

A. A –SIP Scenario‖ that reflects retrofit plans and compliance dates under currently proposed State Implementation Plans in Wyoming, Utah, and Arizona, as well as the approved plan in Colorado; and,

B. An –EPA Aggressive BART Scenario‖ that depicts EPA's proposed FIP in Wyoming, EPA's proposed FIP in Arizona, a FIP in Utah that would require installation of SCR at PacifiCorp's units within five years, and Colorado's approved SIP.

Figure 1 below shows the monthly load and resource balance between 2012 and 2018 for an EPA Aggressive BART Scenario, incorporating the impact of potential emission control retrofit –tie-in‖ outage schedules that could reasonably be anticipated to result from EPA's ongoing SIP reviews based on past EPA actions across the country.[10]

Figure 1
PacifiCorp System Load and Demand versus Available Resources
EPA Aggressive BART Scenario - Forecasted 2013 through 2018



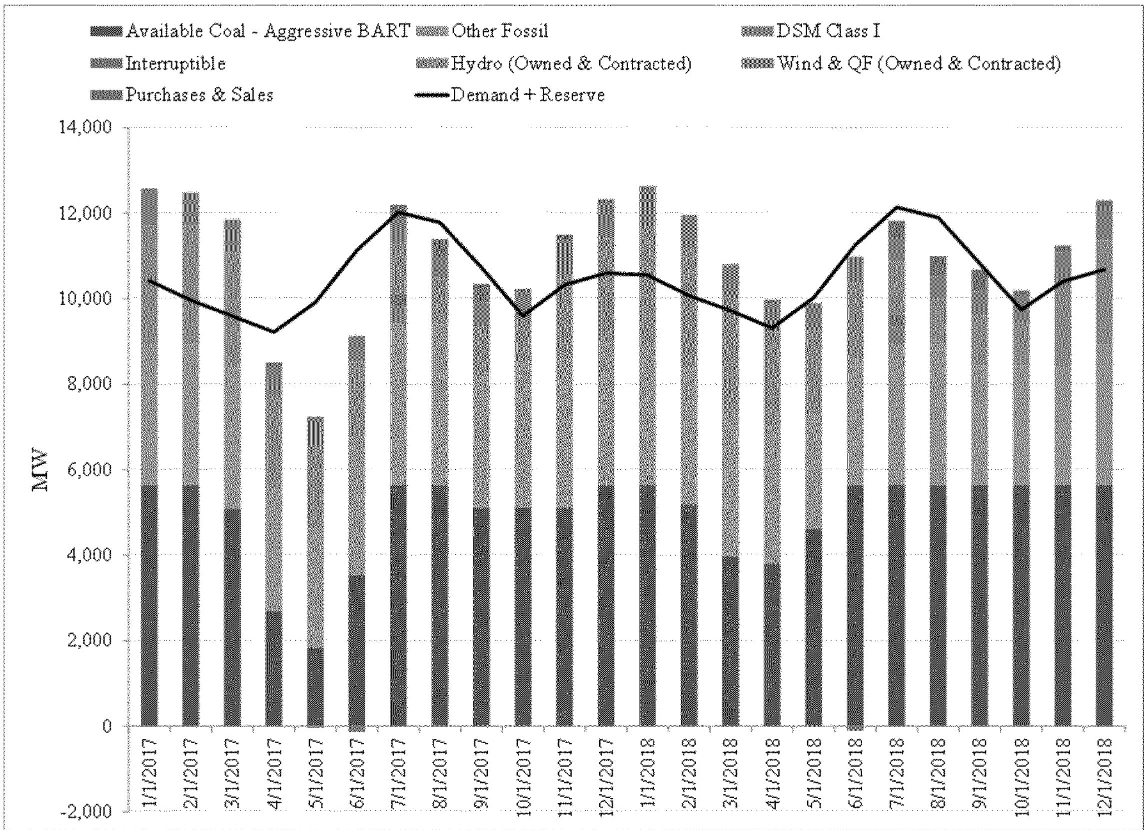
Note: Negative figures correspond to net firm contract sales.

Figure 1 above clearly shows the reduction in coal capacity that occurs each Spring under the planned outage schedules that generally coincide with lower Spring demand. Notably, in the Spring of 2017, primarily as a result of the additional outages required to tie in the SCRs potentially required under the EPA Aggressive BART scenario, demand significantly outstrips supply. Figure 2 below magnifies 2017 and 2018 to more closely examine these years.

[Figure 2 on next page]

[10] Details regarding the requirements and timing under the Aggressive BART Scenario is provided in the next section.

Figure 2
PacifiCorp System Load and Demand versus Available Resources
EPA Aggressive BART Scenario - Forecasted 2017 through 2018

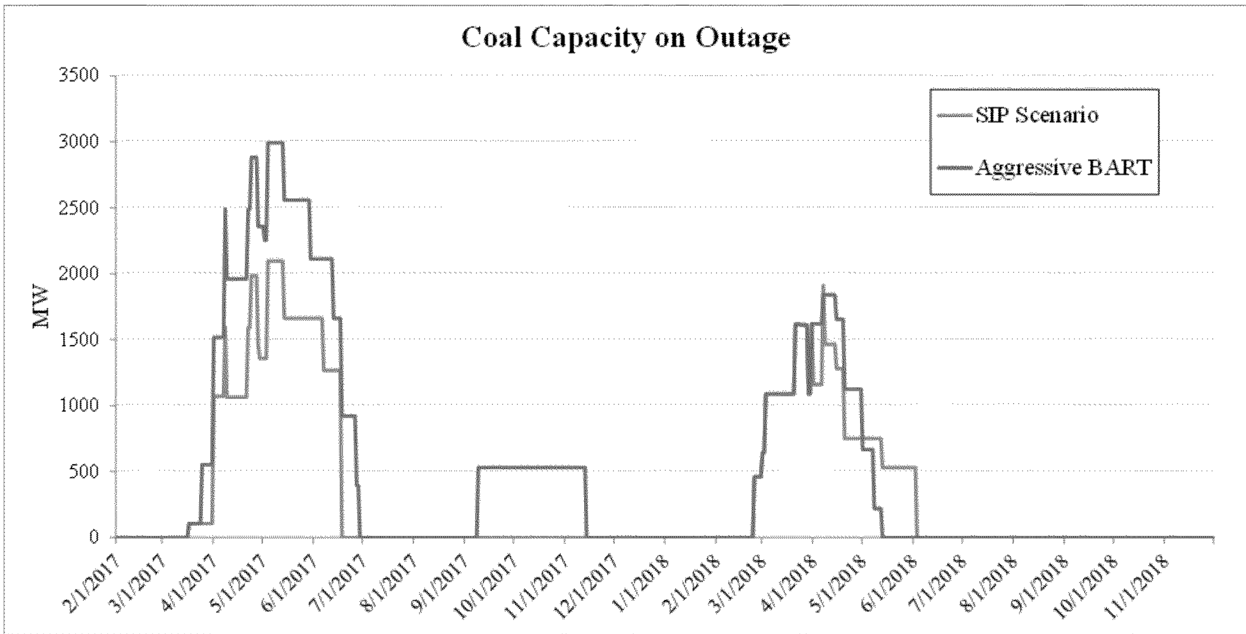


Note: Negative figures correspond to net firm contract sales.

In order to see how the additional EPA Aggressive BART outage time could impact the PacifiCorp system, a more granular picture is helpful. The outage schedule is optimized (and as forecast conditions change, re-optimized) to (1) fit as much planned outage time as necessary to maintain the coal units properly while minimizing the impact on reliability and (2) to rationalize the deployment of labor and equipment resources across the fossil fleet. Additional planned outage days necessary to complete emission control retrofits are accommodated using the same criteria – namely to minimize the overall peak (combined MW) outage impact while scheduling the extended outages to ―fit‖ into the low-load Spring season without unduly extending the overall outage season back into the winter months or forward into the summer months. Figure 3 below shows two (optimized) planned outage schedules through the 2017 and 2018 outage planning window, under the SIP Scenario and the EPA Aggressive BART scenario.

[Figure 3 on next page]

Figure 3
PacifiCorp Coal Capacity on Planned Outage
Current SIP Obligations versus EPA Aggressive BART Scenario
Forecasted 2017 through 2018



As shown in Figure 3 above, the outage season in the Spring of 2017 would begin identically during the third week of March, but the EPA Aggressive BART scenario outages would exceed the SIP Scenario outages about a week after, and remain higher for the duration of the outage season, which would be extended through the end of June in the EPA Aggressive BART Scenario. For most of April and May, the difference between the two scenarios is over 900 MW of additional coal capacity that will be out of production due to the emissions control retrofit ―tie-in‖ outage extensions.

The outage season in the Fall of 2017 would result in approximately 500 MW of previously available coal capacity being out of production for a period of time, and the Spring 2018 outage would begin identically at the end of February with an extended peak outage duration under the EPA Aggressive BART scenario.

Since available replacement power is likely to cost more than PacifiCorp coal generation, those additional costs should be ascribed to complying with the Regional Haze Program, should the EPA Aggressive BART Scenario become required. While there would be some additional resource adequacy risk involved, quantifying that risk in terms of the increased probability of failing to meet load requires a much more complex analysis. However, the figure does depict the challenges that PacifiCorp would face in maintaining reliability under a more stringent program to curb Regional Haze, particularly in 2017.

The additional outage time required for retrofits in the 2017 through 2018 period under the EPA Aggressive BART scenario poses challenges and risks for PacifiCorp. Meeting those challenges would require procuring additional resources during the outage months beyond those currently envisioned in the IRP, which may or may not be readily obtainable in the market (depending on prevailing conditions at the time) and at unknown costs.

5. Planning for Grid Reliability

Similar to the potential system resource adequacy risk discussed above, quantifying the reliability risks that PacifiCorp's transmission system may face under the EPA Aggressive BART scenario requires a much more complex analysis than can reasonably be completed in the timeframe requested by the EPA for this preliminary assessment. However, the incremental localized reduction in available coal capacity underlying the EPA Aggressive BART outage planning scenario depicted in Figure 3 above would be expected to pose operational challenges and risks for PacifiCorp. These challenges unnecessarily pose increased risks and cost to customers that EPA's third proposed alternative would minimize.

Unprecedented Level of Retrofit Activity

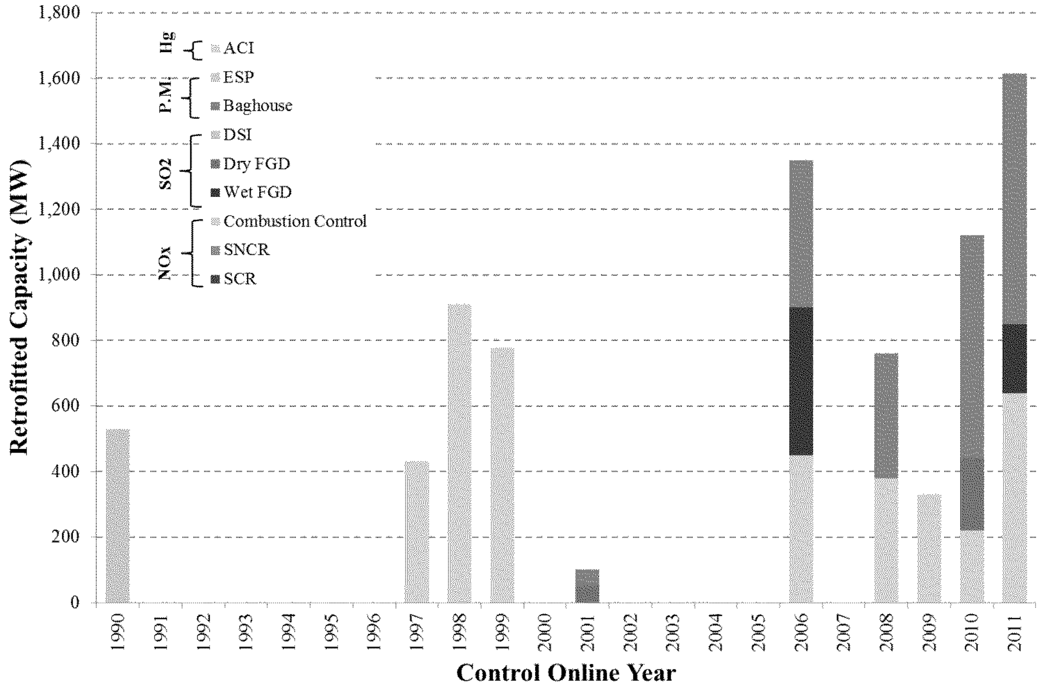
The EPA's FIP would result in an unprecedented level of retrofit activity on PacifiCorp's system, creating significant new issues not previously experienced, including those described below:

Historic Retrofit Activity

For historical perspective, a view of the environmental retrofits completed at power plants in the PacifiCorp region over the past two decades is detailed below in Figure 4 by in-service year and technology type.

[Figure 4 on next page]

Figure 4
Historical Quantities of Retrofits in PacifiCorp Region



Notes:
All generation fuel types are represented; individual units may be represented more than once if subject to multiple retrofits.

As shown in Figure 4 above, the pace of retrofitting environmental controls has accelerated substantially in the past six years, with significant capacity retrofitted with enhanced controls for NO_x, SO_2, and PM, with some units receiving controls for all three pollutants. Note that while Figure 4 is a plot of the equipment online date, construction of the individual retrofits may be presumed to occur before the in-service year.

Because implementation and retrofit of these controls vary significantly in capital costs and project complexity, in order to normalize the data set, all types of major environmental retrofit projects are converted into their wet FGD equivalent MW according to the conversion rates in Table 3 below. Following the convention used by the EPA in a recent study, this conversion is based on the capital costs of each type of control upgrade as listed. [11] Using these conversions, one MW of upgrades from any type of control technology would be normalized to have the same capital cost and approximate supply chain implications.

[Table 3 on next page]

[11] *An Assessment of the Feasibility of Retrofits for the Mercury and Air Toxics Standards Rule*. December 16, 2011. Retrieved from http://www.epa.gov/ttn/atw/utility/revised_retrofit_feasibility_tsd_121611.pdf

Table 3
Wet FGD Equivalence of Retrofit Technologies

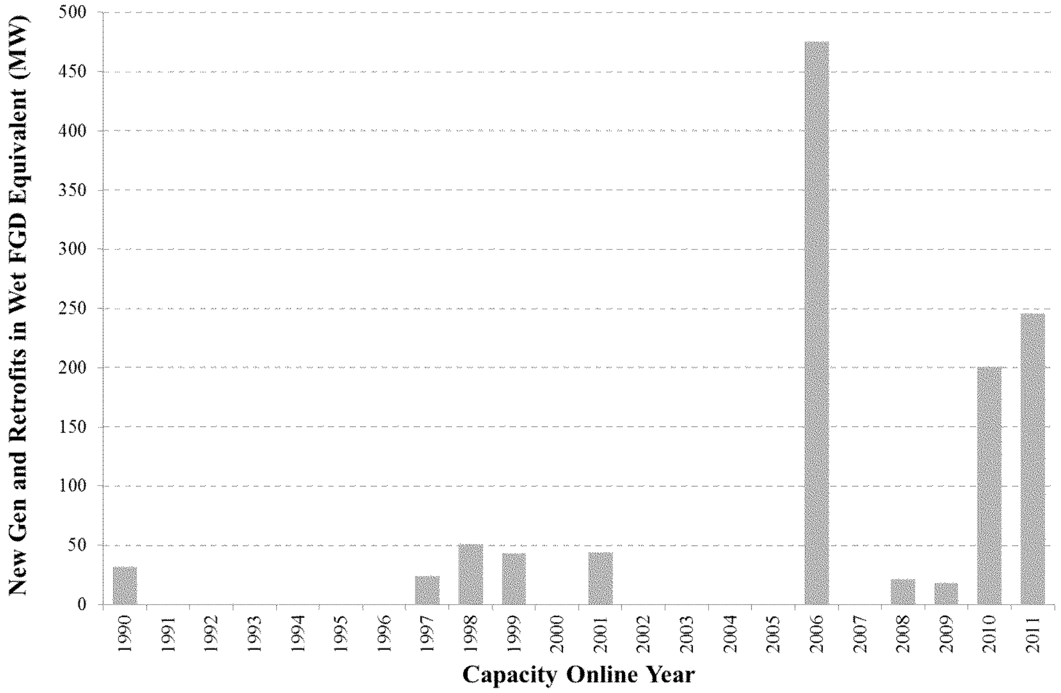
Retrofit Equipment	**Capital Cost** *(2011$/kW)*	**Wet FGD Equivalent** *(MW)*
Coal		
SCR	$223	0.33
SNCR	$51	0.07
Dry FGD	$585	0.86
Wet FGD	**$683**	**1.00**
DSI	$41	0.06
Baghouse	$353	0.52
ESP	$70	0.10
ACI	$26	0.04
Combustion Controls	$41	0.06
Wet FGD Upgrades	--	0.20
Dry FGD Upgrades	--	0.20
ESP Upgrades	--	0.10
Oil/Gas		
Coal SCR		--
Coal SNCR		--
SCR	$64	0.09
SNCR	$13	0.02

Sources and Notes:
Capital costs of retrofit on coal plants from EPA: *IPM Base Case v.4.10.* Chapter 5. August 2010 and EEI: *Potential Impacts of Environmental Regulation on the U.S. Generation Fleet. Final Report.* January 2011.
Oil/gas costs from year 2004 estimate inflated by ratio of coal SCR and SNCR cost inflation between 2004 and 2011 from the same sources.

The total control retrofits reported in Figure 4 above can be converted into their wet FGD equivalent values as shown below in Figure 5.

[Figure 5 on next page]

Figure 5
Historical Retrofits in PacifiCorp Region on a Wet FGD Equivalent Basis



Notes:
Retrofit and new construction MW converted into Wet FGD equivalent basis from Table 1.

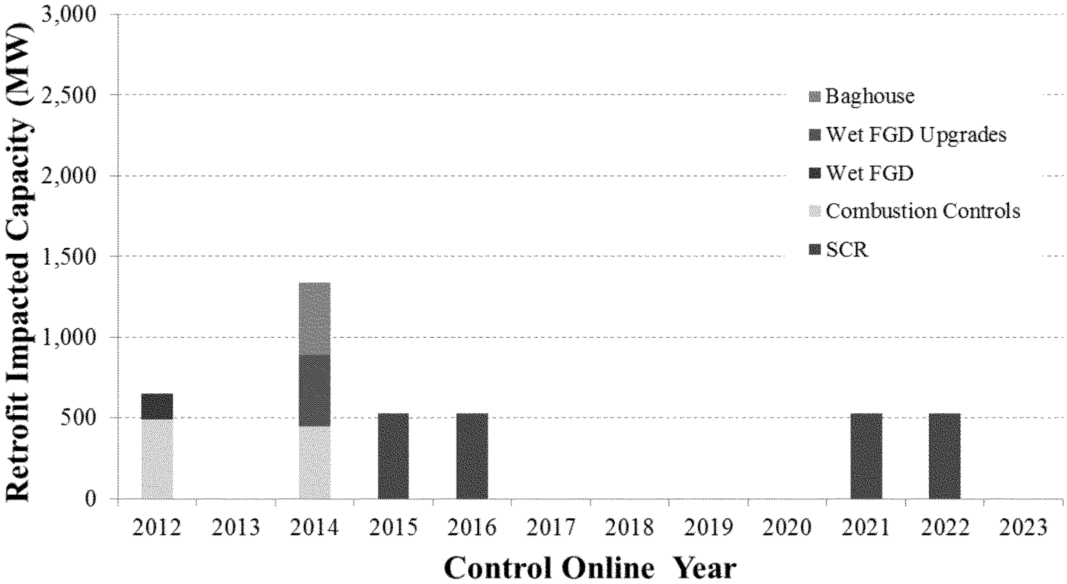
As seen on Figure 5 above, 2006 represented the year when PacifiCorp placed into service the greatest amount of retrofit equipment – about 475 MW on a wet FGD basis. The next highest years – 2011 (246 MW) and 2010 (201 MW) are only about half that level.

Potential Regional Haze Program Retrofit Activity

Two scenarios have been analyzed under two different retrofit compliance assumptions. The ―SIP Scenario‖ reflects the retrofits and compliance dates under the currently proposed State Implementation Plans and the ―EPA Aggressive BART‖ depicts proposed and prospective actions by the EPA requiring more stringent application of the Regional Haze program beyond the levels proposed by the respective States. For each scenario, the impacted capacity for various types of retrofit equipment by the retrofit online date is summarized.

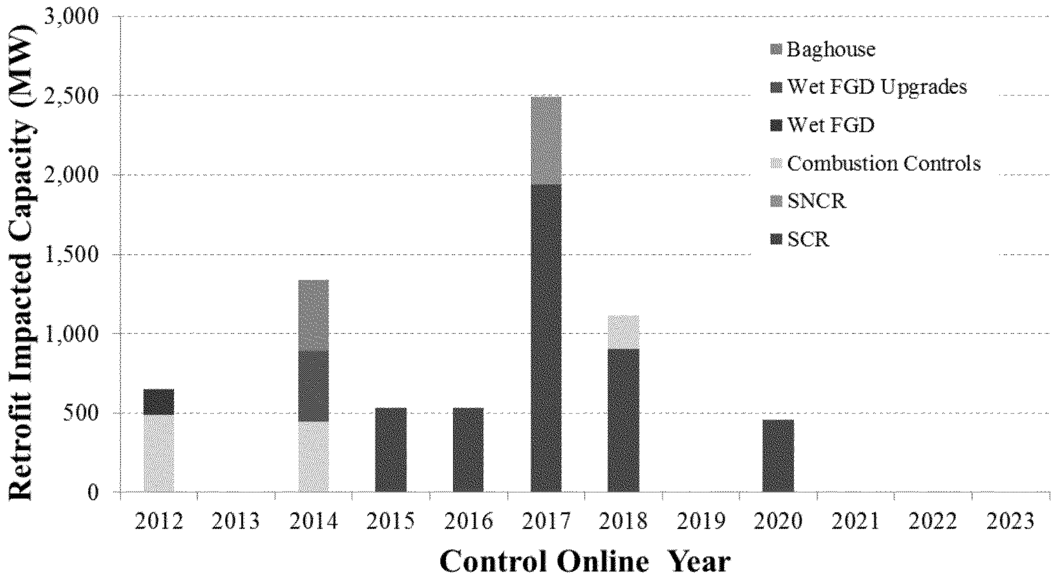
[Figure 6 on next page]

Figure 6
Projected Retrofits in PacifiCorp System
SIP Scenario



The retrofit equipment online schedules under the SIP assumptions are plotted in Figure 6, and similarly, Figure 7 depicts the online schedules for the retrofits under EPA Aggressive BART assumptions.

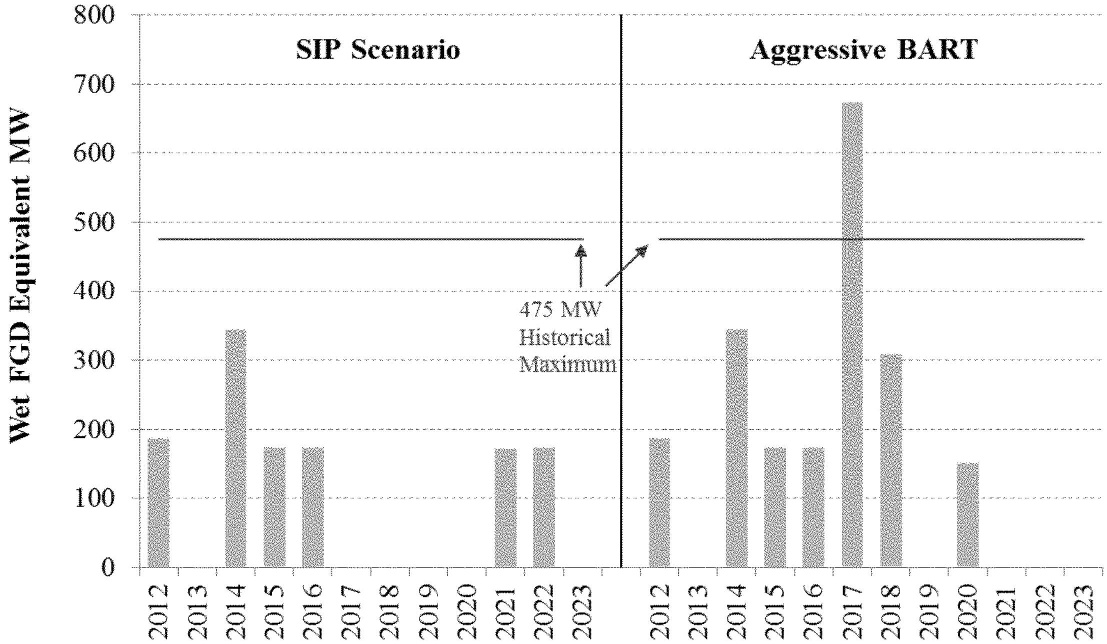
Figure 7
Projected Retrofit in PacifiCorp System
EPA Aggressive BART Scenario



In order to compare with historic levels of retrofit activity, retrofit impacted capacities under the SIP and EPA Aggressive BART scenarios were converted into Wet FGD equivalents in Figure 8, along with the historic annual benchmark of 475 MW.

The differences between the SIP Scenario and the Aggressive BART Scenario are fairly substantial on an equivalent Wet FGD basis. In the SIP Scenario, only one year exceeds the 2010-2011 levels of retrofit investment (of about 225 MW/year), while retrofits placed in service in 2017 (675 MW) substantially exceed the previous historic maximum of 475 MW by 200 MW and two years are above the 2010-2011 level. The control installation requirements under the EPA Aggressive BART Scenario would result in more work, less time, and increased costs.

Figure 8
Projected Retrofit in PacifiCorp System Relative to Historical Maximum



Notes:
Historical maximum from Figure 5 above.
Conversions to Wet FGD equivalent from Table 3 above.

<u>Supply Chain and Labor Considerations</u>

When considered independently from other environmental requirements, the retrofits required under either Regional Haze compliance scenario are not anticipated to impose undue stress on the national supply chain for specialized labor, materials and equipment. However, analyses of compliance with the Mercury and Air Toxics Standard (MATS) have raised concerns that requiring much of the U.S. coal fleet to retrofit or retire in a 3 to 5 year time frame (partially overlapping the compliance time period under the Regional Haze Program) will challenge the equipment construction industry. A study performed for the Midwest Independent Transmission System Operator (MISO) analyzed compliance with MATS by 2015 -2016 and identified potential bottlenecks in labor and equipment that might accompany the retrofit and capacity replacement activities in that region.[12] PacifiCorp is not aware of any study that has assessed the potential interaction between the Regional Haze Program requirements and other environmental requirements such as the investments implied by MATS. In addition to the MATS requirements, additional pressure will be placed on labor and equipment from the Cross-State Air Pollution Rule (–CSAPR‖) or its successor, as utilities in the Eastern U.S. install scrubbers and SCR or SNCR to meet their obligations under a Transport Rule. To the extent that MATS and CSAPR or other environmental requirements create pressure on labor and equipment supplies, that pressure will be increased by the Regional Haze requirements for installation of controls within a five year period as is being proposed and/or adopted by EPA in the Western U.S.

Figure 8 shows that over half of the PacifiCorp retrofit activity in the SIP Scenario occurs in the 2014-2016 timeframe, during which coal units across the U.S. will likely comply with MATS and compete for many of the same resources. This raises the prospect of higher costs and delays associated with completing retrofit projects in this timeframe, assuming that MATS compliance stays on its current schedule. Moreover, while the MATS compliance schedule will not accelerate, there remains a possibility that the MATS compliance deadlines could be delayed as a result of legislative or other action at the national level. If this were to happen, some of the stress on supply chains would be alleviated under the SIP Scenario. However, any delayed compliance with MATS would then coincide with the retrofits necessary to comply with the EPA Aggressive BART scenario. There is also some overlap between the labor and equipment markets for environmental retrofits and new capacity construction, both regionally and nationally, which may affect the accessibility and cost of these resources during a period of aggressive Regional Haze Program retrofits.

Wyoming and EPA are Legally Required to Consider the Economic and System Impacts on PacifiCorp and Its Customers

EPA must include the information provided herein as part of its analysis of Wyoming's Regional Haze SIP and EPA's proposed Regional Haze FIP. As EPA's Regional Haze guidance, Appendix Y, explains:

> There may be unusual circumstances that justify taking into consideration the . . . economic effects of requiring the use of a given control technology. These effects would include effects on product prices. . .

[12] See *Supply Chain and Outage Analysis of MISO Coal Retrofits for MATS* by The Brattle Group, May 2012. This report also surveyed other supply chain studies, providing a range of potential effects from MATS compliance.

> Where these effects are judged to have a severe impact on plant operations you may consider them in the selection process, but you may wish to provide an economic analysis that demonstrates, in sufficient detail, for public review, the specific economic effects, parameters, and reasoning.

Appendix Y, IV.E.3. Given the large number of BART impacted units owned by PacifiCorp in different states, these –unusual circumstances‖ justify Wyoming's BART actions on PacifiCorp's facilities and PacifiCorp's customers.

Regional Haze is Primarily a State Issue and the Wyoming SIP Schedule Should be Maintained

The Clean Air Act and EPA's own rules require Regional Haze requirements to be determined and implemented at the state level. In Wyoming, however, EPA has elected to reject part of Wyoming's carefully-crafted SIP and replace it with its own. This is not how the Regional Haze program is supposed to work. PacifiCorp believes that EPA's proposal fails to give proper deference to the State of Wyoming's Regional Haze determinations as required by the Clean Air Act.

The Wyoming Department of Environmental Quality conducted a robust BART analysis. In doing so, it exercised the very discretion contemplated by the Clean Air Act in applying the relevant factors to its BART determinations. These factors, found in EPA's own requirements, included consideration of issues such as those identified herein. The EPA should not substitute its judgment for that of Wyoming, particularly when Wyoming has taken into consideration the issues that are important to the State of Wyoming, its citizens, PacifiCorp and our customers, such as grid reliability, costs and the complexity of PacifiCorp's integrated electricity system and resources.

PacifiCorp urges EPA to adopt the third proposed approach, providing additional time for PacifiCorp to manage the system impacts of controls and costs. The emission reductions achieved by accelerating the SCR at the Jim Bridger facility by four to five years pale in comparison to the emission reductions already achieved under the Wyoming Regional Haze SIP. PacifiCorp's later comments will address this issue in more detail. Moreover, nothing in this submission should be interpreted as PacifiCorp's agreement with any of EPA's proposed Regional Haze FIP. As PacifiCorp will explain in its later comments, PacifiCorp completely disagrees with EPA's proposed Regional Haze FIP.

PacifiCorp appreciates the opportunity to provide comments on the EPA alternative proposals for PacifiCorp's Jim Bridger Units 1, 2, 3, and 4 NO_x BART. Additional, extensive comments on the balance of EPA's proposed action will follow.

Respectfully submitted,

Micheal G. Dunn
President and Chief Executive Officer
PacifiCorp Energy
1407 West North Temple
Salt Lake City, UT 84116
(801) 220-4893

Attachment 14

Steve Dietrich, Wyoming's Air Quality Administrator, testified in a public hearing in Cheyenne, Wyoming on June 26, 2012 regarding regional haze issues. As part of his testimony, he explained how the timing of the regional haze program, and why EPA should not force controls into the first planning period.

> The Regional Haze Rule is a unique federal rule in many ways, but the most unusual aspect of the rule is the time frame that it attempts to cover. The rule looks forward 60 years with the goal of r eturning visibility to natural conditions by 2064. Many of us that are currently working on this problem will not be alive when the goals of this program are attained. . .
>
> EPA recognized that as a long-term program the states would need to address overall goals in smaller pieces. In 40 CFR 51.308(f), EPA placed a requirement to 20 submit comprehensive state implementation revisions in 2018 and every 10 years thereafter, which means SIP revisions in the year 2018, 2028, 2038, 2048, and 2058. So states will be doing five more comprehensive regional haze SIPs before the year 2064. In addition to the comprehensive SIP revisions, states are also required under 40 CFR 51.308(g) to submit progress reports in the form of a SIP revision every five years. With the first revision due in 2013 and every five years thereafter, the State will be doing 11 progress reports and SIP revisions. Between the comprehensive SIP revisions and the not so comprehensive SIP revisions, the states will be submitting at a minimum 16 mo re SIP revisions to address regional haze. It is very possible that the number could be higher than 16 SIP revisions because the State of Wyoming has already submitted four regional haze SIP revisions for the first planning period alone. This was not the S tate's choice, but intervening lawsuits and changes to the Regional Haze Rule required changing the plan multiple times.
>
> Our point in outlining all of this -- all the increments in the long -range plan is to underscore EPA's intention to give states some ti me to get the job done. EPA never intended for states to attain all of the reductions in the first planning period. There are no requirements in the rule to hit certain emissions reductions by a certain period of time. In fact, EPA recognizes in the pream ble that many things will change over time and that it may be possible to get emissions reductions in the future that cannot be procured at an earlier time. On page 35732 of the July 1st, 1999 Regional Haze preamble, EPA says, "In the longer term, it can be expected that continued progress in visibility impairment will be possible as industrial facilities built in the latter half of the 20th century reach the end of their useful lives and are retired and/or placed by – replaced by cleaner, more fuel - efficient facilities. Significant improvements in pollution prevention techniques, emission control technologies, and renewable energy have been made over the last -- past 30 years and continue to be made. History strongly suggests that further innovations in control technologies are likely to continue in future decades, leading to the ability of the new plants to meet lower emission rates.

Pages 46 through 48 of the Transcript from the Public Hearing, available at: http://www.regulations.gov/#!searchResults;dct=PS;rpp=25;po=0;s= EPA-R08-OAR-2012-0026.

Attachment 15

EPA-R8-2014-0028860001469

Future Clean Air and CCR Project Cash Flow Template

Project Name:	SNCR System	YELLOW CELLS SHOULD BE COMPLETED
Plant:	Dave Johnston	
Unit:	3	
Implementation APR Number:	(Later)	
Plant Project Coordinator:	(Later)	
ResD Project Manager:	(Later)	
In-Service Year:	2018	
In Service Month:	November, 2018	
Version Date:	8/23/2013	
Development APR # (if applicable)	(Later)	

Capital Project Implementation Costs (without AFUDC)

Development	···········>	$ -	Total Costs All Years for Development
Implementation (Project Execution)	···········>	$ 8,996	Total Costs All Years for Implementation

Operations and Maintenance Costs (current year dollars only)

Chemicals

	Cost Per Unit $/Unit)	Units (Tons, lbs, gals, ?)	Use Rate (Units/hr)	Data Owner/Source
Reagent A (Urea, 50% Solution; 85% annual capacity factor)	$ 400	Tons	0.304	SL, ResD, 1308
Reagent B (_____________________)				
Reagent C (_____________________)				

Operations and Maintenance (Non-Chemicals)

	$/Year ($000)	Data Owner/Source
Incremental plant labor (including OT) attributable to project	$ 235	SL, ResD
Incremental parts, materials, contracts, fees, royalties	$ 58	SL, ResD
Demineralized water, (for urea solution dilution)	$ 43	SL, ResD
Other Consumables (solvents, lubricants, greases)		

Ongoing Capital (Current year dollars)

	Cost ($000S)	Frequency (once every X? years)	Data Owner/Source
Periodic Major Replacments (i.e. catalyst replacement) - Type 1			
Periodic Major Replacments (i.e. catalyst replacement) - Type 2			
Ongoing blanket replacements (i.e. pumps, motors)			

Other (Performance Impacts)

	Change	Data Owner/Source	
Change in Aux Power (in kilowatts, + = increase in Aux. Power)	-50	SL ResD	(Net consumption increase)
Change in Minimum Load (Yes/No?)	No	SL ResD	
New Minimum Load (if applicable, in MW)	NA	SL ResD	

Cash Flow by Year ($000s)

These year fields will update based on In-Service Year >	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
						1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21
Annual Capacity Factor (%), From 10-Yr Plan																										
Annual Generation (MWhs), From 10-Yr Plan																										
Development																										
Implementation (Project Execution)		$ 217	$ 867	$ 2,168	$ 2,168	$ 3,576																				
TOTAL IMPLEMENTATION CAPITAL	$	$ 217	$ 867	$ 2,168	$ 2,168	$ 3,576	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$
Reagent A						$ 151	$ 905	$ 905	$ 905	$ 905	$ 905	$ 905	$ 905	$ 905	$ 905											
Reagent B																										
Reagent C																										
Sub-Total, Chemicals	$ -	$ -	$ -	$ -	$ -	$ 151	$ 905	$ 905	$ 905	$ 905	$ 905	$ 905	$ 905	$ 905	$ 905	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Incremental plant labor						$ 39	$ 235	$ 235	$ 235	$ 235	$ 235	$ 235	$ 235	$ 235	$ 235											
Incremental parts, materials, contracts, fees, royalties						$ 10	$ 58	$ 58	$ 58	$ 58	$ 58	$ 58	$ 58	$ 58	$ 58											
Demineralized water						$ 7	$ 43	$ 43	$ 43	$ 43	$ 43	$ 43	$ 43	$ 43	$ 43											
Other Consumables																										
Sub-Total, Non-Chemical O&M	$	$	$	$	$	$ 49	$ 293	$ 293	$ 293	$ 293	$ 293	$ 293	$ 293	$ 293	$ 293	$	$	$	$	$	$	$	$	$	$	$
TOTAL OMAG	$ -	$ -	$ -	$ -	$ -	$ 200	$ 1,198	$ 1,198	$ 1,198	$ 1,198	$ 1,198	$ 1,198	$ 1,198	$ 1,198	$ 1,198	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Periodic Major Replacments - Type 1																										
Periodic Major Replacments - Type 2																										
Ongoing blanket replacements																										
TOTAL ONGOING CAPITAL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Purpose:

1. Identify the major assumptions for long term ownership of the project (capital, ongoing capex and omag for 20 years following the inservice date of the project.
2. Provide a common database for project APR and plant budgets
3. Identifies the "owners" or originators of the major data assumptions
4. This is intended as a summary level roll up document; it may not include all of detailed calculations required to provide the summary information.

Assumptions:
1. 100% share
2. Costs do not include AFUDC.
3. All current year cost basis (i.e. no escalation); 2013 dollars.
4. December 31, 2027 is end of depreciable life.
5. Capacity factor equals 85%
6. Urea solution utilization rate used was 32%
7. Baseline (inlet) NOx concentration was 0.22 lb/mmBtu (average basis)
8. NOx permit limit assumed was 0.21 lb/mmBtu, 30 boiler operating day rolling average, controlled to 0.19 lb/mmBtu

Notes:

Reagent costs based on costs delivered to plant including freight and taxes
Development costs will be project specific (not all projects will have a development APR)

Attachment 16

Department of Environmental Quality

To protect, conserve and enhance the quality of Wyoming's

environment for the benefit of current and future generations.

Matthew H. Mead, Governor

Todd Parfitt, Director

July 5, 2013

Mr. William K. Lawson
Environmental Manager
PacifiCorp Energy
1407 W. North Temple, Suite 330
Salt Lake City, UT 84116

CERTIFIED – RETURN RECEIPT REQUESTED

Re: Air Quality Permit No. MD-14506

Dear Mr. Lawson:

The Division of Air Quality of the Wyoming Department of Environmental Quality has completed final review of PacifiCorp Energy's application to modify the Naughton Power Plant by reducing permitted emissions from Unit 3 and ultimately converting the unit from a coal-fired electric generating unit to a natural gas-fired unit in 2018. The Naughton Plant is located in sections 32 and 33, T21N, R116W, approximately four (4) miles southwest of Kemmerer, in Lincoln County, Wyoming. Comments were received from PacifiCorp Energy on June 14, 2013; and on June 17, 2013 from the United Mine Workers of America Local 1307; from Westmoreland Kemmerer, Incorporated; and from the Lincoln Conversation District. All comments were considered in the final permit and are addressed below.

Comments from the United Mine Workers of America Local 1307; Westmoreland Kemmerer, Incorporated; and the Lincoln Conservation District

Comments: The United Mine Workers of America Local 1307 and Westmoreland Kemmerer, Incorporated oppose the permitting action that would allow the conversion of Naughton Unit 3 to a natural gas-fired unit. Both commenters state that controls could be used on the existing unit to achieve compliance with EPA standards. Both commenters also cite the potential reduction in the workforce at the Kemmerer Mine, reduction in tax revenue, and a potential loss of school district funding as the reasons for their opposition. The Lincoln Conservation District commented that the price of natural gas could rise in the future, which could increase rates for electricity from gas-fired units. They also cite the potential loss of tax revenue and impact to local budget cuts, and concur that pollution controls could be used on the existing coal-fired unit to achieve compliance with EPA standards.

Responses: The Division grants air quality permits for the construction or modification of air pollution sources based on compliance with the Wyoming Air Quality Standards and Regulations. The Division does not dictate fundamental design of the applicant's facility or the applicant's choice of fuels or the cost of those fuels. We do not have the authority to deny an air quality permit for a proposed project because of a project's impact on tax revenue or the local economy. We do consider the costs of the air pollution control equipment that is proposed for the facility, but only to ensure that Best Available Control Technology (BACT) is being applied in accordance with the WAQSR.

PacifiCorp Energy's Comments

Comment: Permit Conditions 6.ii.4 and 10 – PacifiCorp stated that it intends to implement the requirements imposed by Condition 6.ii beginning April 1, 2015, and requests that Conditions 6.ii.4 and 10 be revised to require that initial performance testing be completed within 30 boiler operating days from April 1, 2015. PacifiCorp also notes that Condition 10 refers to limits contained in Condition 5.ii that are actually stated in 6.ii.

Response: The Division will retain the effective date of the emission limits shown in 6.ii.4, but will revised the timeframe for initial performance testing from April 1, 2015 to within 30 boiler operating days from April 1, 2015 in accordance with Chapter 6, Section 2(j) of the Wyoming Air Quality Standards and Regulations (WAQSR). Condition 10 will be revised to correctly refer to the limits in Condition 6.ii rather than 5.ii.

Comment: Permit Conditions 6.iii.4 and 11 – PacifiCorp intends to complete the conversion of Unit 3 and place the unit in service as a natural gas unit prior to June 30, 2018. Therefore, the requirement that initial performance testing for limits under 6.iii.4 be complete by December 31, 2017 cannot be met. PacifiCorp also notes that Condition 11 refers to limits contained in Condition 5.iii that are actually stated in 6.iii.

Response: The Division's intent in requiring testing under Condition 6.iii.4 by December 31, 2017 was to ensure that Unit 3 would not be fueled by coal beyond that date, as represented in the application. To allow PacifiCorp the time needed to make the conversion of Unit 3 to a natural gas-fired unit, the Division will extend the initial performance testing requirement to 90 calendar days following startup of the unit on natural gas. The Division will require that the coal pulverizers for Unit 3 be removed from service no later than January 1, 2018, in accordance with PacifiCorp Energy's comment, to ensure that Unit 3 does not operate on coal during the conversion to a natural gas-fired unit. Condition 11 will be revised to correctly refer to the limits specified in Condition 6.iii rather than 5.iii.

Comment: Permit Conditions 6.iii.2 and 11.i.2 - PacifiCorp requests that the 2-hour rolling average limit and the 3-hour block average limit for SO_2 be removed. PacifiCorp also requests that the requirement to determine SO_2 emissions using a continuous emissions monitoring system (CEMS) be replaced with a method using gas flow and an emissions factor from 40 CFR part 75.

Response: The Division will not grant these requests without a demonstration on the part of the applicant that the remaining emissions limits for SO_2 will allow for the same level of air quality protection as the limits that are requested for removal. The SO_2 limits for Naughton Unit 3 will remain as proposed. If PacifiCorp Energy provides a demonstration to revise the SO_2 limits, then the Division will consider revising the applicable monitoring requirements based on the averaging period of the determined limits.

Comment: Permit Conditions 13.i.1 and 13.i.3 - PacifiCorp requests that the 30-day and 12-month rolling average emission limits be based on the summation of hourly emissions divided by the summation of hourly heat input for the same time period.

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Response: The Division will retain the methods specified in Conditions 13.i.1 and 13.i.3 to define exceedances of the emission limits as they are consistent with existing methods specified in other air quality permits for the Naughton Plant. The Division does not anticipate that the requested methods would yield results appreciably different from those produced by the methods required in the draft permit.

Comment: Permit Condition 20 - PacifiCorp intends to complete the conversion of Unit 3 and place the unit in service as a natural gas unit prior to June 30, 2018, therefore they request that Condition 20 be modified to reflect that the conversion must be completed prior to June 30, 2018, and that initial performance tests be completed within 90 days of initial startup on natural gas.

Response: The Division's intent in requiring the conversion of Unit 3 and initial testing by December 31, 2017 was to ensure that Unit 3 would not be fueled by coal beyond that date, as represented in the application. To allow PacifiCorp the time needed to make the conversion of Unit 3 to a natural gas-fired unit, the Division will extend the initial performance testing requirement to 90 calendar days following the startup of the unit on natural gas. The Division will require that the coal pulverizers for Unit 3 be removed from service no later than January 1, 2018 to ensure that Unit 3 cannot operate on coal during the conversion to a natural gas-fired unit.

If we may be of further assistance to you, please feel free to contact this office.

Sincerely,

Steven A. Dietrich

Steven A. Dietrich
Administrator
Air Quality Division

cc: Greg Meeker

Department of Environmental Quality

To protect, conserve and enhance the quality of Wyoming's environment for the benefit of current and future generations.

Matthew H. Mead, Governor

Todd Parfitt, Director

July 5, 2013

Mr. William K. Lawson
Environmental Manager
PacifiCorp Energy
1407 W. North Temple, Suite 330
Salt Lake City, UT 84116

Permit No. **MD-14506**

Dear Mr. Lawson:

The Division of Air Quality of the Wyoming Department of Environmental Quality has completed final review of PacifiCorp Energy's application to modify the Naughton Power Plant by reducing permitted emissions from Unit 3 and ultimately converting the unit from a coal-fired electric generating unit to a natural gas-fired unit in 2018. The Naughton Plant is located in sections 32 and 33, T21N, R116W, approximately four (4) miles southwest of Kemmerer, in Lincoln County, Wyoming.

Following this agency's proposed approval of the request as published May 16, 2013 and in accordance with Chapter 6, Section 2(m) of the Wyoming Air Quality Standards and Regulations, the public was afforded a 30-day period in which to submit comments concerning the proposed modification, and an opportunity for a public hearing. Comments were received and considered in the issuance of the final permit. Therefore, on the basis of the information provided to us, approval to modify the Naughton Power Plant as described in the application is hereby granted pursuant to Chapter 6, Section 2 of the regulations with the following conditions:

1. That authorized representatives of the Division of Air Quality be given permission to enter and inspect any property, premise or place on or at which an air pollution source is located or is being constructed or installed for the purpose of investigating actual or potential sources of air pollution and for determining compliance or non-compliance with any rules, standards, permits or orders.

2. That all substantive commitments and descriptions set forth in the application for this permit, unless superseded by a specific condition of this permit, are incorporated herein by this reference and are enforceable as conditions of this permit.

3. PacifiCorp Energy shall file a complete application to modify their Operating Permit within twelve (12) months of commencing operation, in accordance with Chapter 6, Section 3(c)(i)(B) of the WAQSR.

4. All notifications, reports and correspondence associated with this permit shall be submitted to the Stationary Source Compliance Program Manager, Air Quality Division, 122 West 25th Street, Cheyenne, WY 82002 and a copy shall be submitted to the District Engineer, Air Quality Division, 510 Meadowview Drive, Lander, WY 82520.

5. For the conversion of Naughton Unit 3 to natural gas, the owner or operator shall furnish the Administrator written notification of: (i) the anticipated date of initial startup not more than 60 days or less than 30 days prior to such date, and; (ii) the actual date of initial start-up within 15 days after such date in accordance with Chapter 6, Section 2(i) of the WAQSR.

6. This condition shall supersede portions of Condition 5 of Air Quality Permit MD-11725 as it pertains to Naughton Unit 3. Condition 5, Unit 3, Condition i. of MD-11725 shall remain in effect. Emissions from Naughton Unit 3 shall not exceed the levels below:

Unit 3

ii. Effective April 1, 2015:
1. NO_x: 0.75 lb/MMBtu; 3-hour rolling average
0.40 lb/MMBtu; 30-day rolling average
1,258.0 lb/hr; 30-day rolling average
4,700 tons per calendar year
a. Limits shall apply during all operating periods.
2. SO_2: 0.5 lb/MMBtu; 2-hour rolling average
0.20 lb/MMBtu; 30-day rolling average
1,850 lb/hr; 3-hour block average
629.0 lb/hr; 30-day rolling average
2,350 tons per calendar year
a. Limits shall apply during all operating periods.
3. PM: 0.035 lb/MMBtu
110.0 lb/hr
434.0 tons per calendar year
a. Filterable PM/PM_{10}
b. lb/hr limit shall apply during all operating periods.
c. lb/MMBtu shall apply during all operating periods, except startup.
i. Startup begins with the introduction of natural gas into the boiler and ends no later than the point in time when the ESP reaches a temperature of 225°F.
4. Limits in (ii.) above supersede limits in MD-11725, Condition 5(i.) for Unit 3 on and after April 1, 2015. Initial performance tests required by Condition 10 of this permit shall be completed within 30 boiler operating days of April 1, 2015.

iii. Effective upon conversion to natural gas:
1. NO_x: 0.75 lb/MMBtu; 3-hour rolling average
0.08 lb/MMBtu; 30-day rolling average
250.0 lb/hr; 30-day rolling average
519.0 tons per calendar year
a. Limits shall apply during all operating periods.
2. SO_2: 0.5 lb/MMBtu; 2-hour rolling average
0.0006 lb/MMBtu; 30-day rolling average
1,850 lb/hr; 3-hour block average
2.0 lb/hr; 30-day rolling average
4.0 tons per calendar year
a. Limits shall apply during all operating periods.

3. PM: 0.008 lb/MMBtu
   30.0 lb/hr
   52.0 tons per calendar year
   a. Total PM/PM_{10}
   b. Limits shall apply during all operating periods.
4. Limits in (iii.) above supersede limits in (ii.) of this condition for Unit 3 on and after January 1, 2018. Initial performance tests required by Condition 11 of this permit shall be completed within 90 calendar days of startup after conversion to natural gas.

---

7. Effective upon permit issuance, this condition shall supersede Condition 6(i) of Air Quality Permit MD-11725. Opacity shall be limited as follows:

   i. Units 1-2:
      1. No greater than forty percent (40%) opacity of visible emissions.
         a. Limit shall apply during all operating periods.

      Unit 3:
      1. No greater than twenty percent (20%) opacity for visible emissions.
         a. Limit shall apply during all operating periods.
         b. Limit shall become effective upon startup of Unit 3 after natural gas conversion and completion of initial performance tests required by Condition 11 of this permit.

8. Effective upon permit issuance, this condition shall supersede Condition 10 in MD-9861.

   i. Authorization for SO_3 injection on Unit 3 shall remain in effect until start-up of Unit 3 after natural gas conversion and completion of the initial performance tests required by Condition 11 of this permit.

9. Effective upon permit issuance, this condition shall supersede Condition 17 in MD-5156. PacifiCorp Energy shall not be required under MD-5156 to install, calibrate, operate, and maintain a PM continuous emissions monitoring system (CEMS) on Unit 3.

10. Within 30 boiler operating days of April 1, 2015, performance tests shall be conducted on Unit 3 to demonstrate compliance with the limits in Condition 6.ii. and a written report of the results shall be submitted. If the maximum allowable heat input rate established in Condition 15 is not achieved during the performance tests, the Administrator may require testing be done at the rate achieved and again when the maximum allowable rate is achieved. Performance tests shall consist of the following:

    i. Unit 3:

       1. <u>NO_x Emissions</u> – Compliance with the NO_x 3-hour and 30-day rolling averages shall be determined using a continuous emissions monitoring system (CEMS) certified in accordance with 40 CFR part 75.

2. SO_2 Emissions – Compliance with the SO_2 2-hour and 30-day rolling averages and 3-hour block average shall be determined using a continuous emissions monitoring system (CEMS) certified in accordance with 40 CFR part 75.

3. PM/PM_{10} Emissions – Testing shall follow EPA Reference Test Methods 1-4 and 5, or an equivalent EPA Reference Method.

Testing required by the Chapter 6, Section 3, Operating Permit or required by 40 CFR part 63, subpart UUUUU may be submitted to satisfy the testing required by this condition.

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11. Effective upon permit issuance, the applicable requirements of this condition shall supersede Condition 11.ii.2.(Unit 3) of MD-5156. Within 90 calendar days of conversion of Unit 3 to natural gas performance tests shall be conducted on Unit 3 to demonstrate compliance with the limits in Condition 6.iii. of this permit and a written report of the results shall be submitted. If the maximum allowable heat input rate established in Condition 15 of this permit is not achieved during the performance tests, the Administrator may require testing be done at the rate achieved and again when the maximum allowable rate is achieved. Performance tests shall consist of the following:

i. Unit 3:

1. NO_x Emissions – Compliance with the NO_x 3-hour and 30-day rolling averages shall be determined using a continuous emissions monitoring system (CEMS) certified in accordance with 40 CFR part 75.

2. SO_2 Emissions – Compliance with the SO_2 2-hour and 30-day rolling averages and 3-hour block average shall be determined using a continuous emissions monitoring system (CEMS) certified in accordance with 40 CFR part 75.

3. PM/PM_{10} Emissions – Testing shall follow EPA Reference Test Methods 1-5 and 202, or an equivalent EPA Reference Method.
4. CO Emissions - Testing shall follow EPA Reference Test Methods 1-4 and 10 or an equivalent EPA Reference Method.

Testing required by the Chapter 6, Section 3, Operating Permit or required by 40 CFR part 63, subpart UUUUU may be submitted to satisfy the testing required by this condition.

12. Prior to any testing required by this permit, a test protocol shall be submitted to the Division for approval, at least 30 days prior to testing. Notification should be provided to the Division at least 15 days prior to any testing. Results of the tests shall be submitted to this office within 45 days of completing the tests.

13. This condition shall supersede Condition 8 of Air Quality Permit MD-11725 as it applies to Naughton Unit 3. Compliance with the NO_x and SO_2 limits for Naughton Unit 3 set forth in Condition 5(i.) of MD-11725 and Condition 5 of this permit shall be determined with data from the NO_x and SO_2 continuous monitoring systems required by 40 CFR Part 75 as follows:

    i. Exceedances of the limits shall be defined as follows:

        1. Any 12-month rolling average which exceeds the lb/MMBtu NO_x limits as calculated using the following formula:

$$E_{avg} = \frac{\sum_{h=1}^{n}(C)_h}{n}$$

Where:

E_{avg} = Weighted 12-month rolling average emission rate (lb/MMBtu).

C = 1-hour average SO_2 or NO_x emission rate (lb/MMBtu) for hour "h" calculated using valid data from the CEM equipment certified and operated in accordance with Part 75 and the procedures in 40 CFR part 60, appendix A, Method 19. Valid data shall meet the requirements of WAQSR, Chapter 5, Section 2(j). Valid data shall not include data substituted using the missing data procedure in subpart D of Part 75, nor shall the data have been bias adjusted according to the procedures of Part 75.

n = The number of unit operating hours monitored during a boiler operating day in the last twelve (12) successive calendar months with valid emissions data meeting the requirements of WAQSR, Chapter 5, Section 2(j). A "boiler operating day" shall be defined as any 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time at the steam generating unit.

        2. Any 12-month rolling average which exceeds the lb/hr NO_x limit as calculated using the following formula:

$$E_{avg} = \frac{\sum_{h=1}^{n}(C)_h}{n}$$

Where:

E_{avg} = Weighted 12-month rolling average emission rate (lb/hr).

C = 1-hour average emission rate (lb/hr) for hour "h" calculated using valid data (output concentration and average hourly volumetric flowrate) from the CEM equipment certified and operated in accordance with Part 75. Valid data shall meet the requirements of WAQSR, Chapter 5, Section 2(j). Valid data shall not include data substituted using the missing data procedure in subpart D of Part 75, nor shall the data have been bias adjusted according to the procedures of Part 75.

n = The number of unit operating hours monitored during a boiler operating day in the last twelve (12) successive calendar months with valid emissions data meeting the requirements of WAQSR, Chapter 5, Section 2(j). A "boiler operating day" shall be defined as any 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time at the steam generating unit.

3. Any 30-day rolling average which exceeds the lb/MMBtu SO_2 or NO_x limit as calculated using the following formula:

$$E_{avg} = \frac{\sum_{h=1}^{n}(C)_h}{n}$$

Where:

E_{avg} = Weighted 30-day rolling average emission rate (lb/MMBtu).

C = 1-hour average emission rate (lb/MMBtu) for hour "h" calculated using valid data from the CEM equipment certified and operated in accordance with Part 75 and the procedures in 40 CFR part 60, appendix A, Method 19. Valid data shall meet the requirements of WAQSR, Chapter 5, Section 2(j). Valid data shall not include data substituted using the missing data procedure in subpart D of Part 75, nor shall the data have been bias adjusted according to the procedures of Part 75.

n = The number of unit operating hours in the last thirty (30) successive boiler operating days with valid emissions data meeting the requirements of WAQSR, Chapter 5, Section 2(j). A "boiler operating day" shall be defined as any 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time at the steam generating unit.

4. Any 30-day rolling average which exceeds the lb/hr SO_2 or NO_x limits as calculated using the following formula:

$$E_{avg} = \frac{\sum_{h=1}^{n} (C)_h}{n}$$

Where:

E_{avg} = Weighted 30-day rolling average emission rate (lb/hr).

C = 1-hour average emission rate (lb/hr) for hour "h" calculated using valid data (output concentration and average hourly volumetric flowrate) from the CEM equipment certified and operated in accordance with Part 75. Valid data shall meet the requirements of WAQSR, Chapter 5, Section 2(j). Valid data shall not include data substituted using the missing data procedure in subpart D of Part 75, nor shall the data have been bias adjusted according to the procedures of Part 75.

n = The number of unit operating hours in the last thirty (30) successive boiler operating days with valid emissions data meeting the requirements of WAQSR, Chapter 5, Section 2(j). A "boiler operating day" shall be defined as any 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time at the steam generating unit.

5. Any 3-hour rolling average of NO_x emissions calculated using data from the CEM equipment required by 40 CFR part 75 which exceeds the lb/MMBtu limit established in this permit using valid data. Valid data shall meet the requirements of WAQSR, Chapter 5, Section 2(j). The 3-hour average emission rate shall be calculated as the arithmetic average of the previous three (3) operating hours.

6. Any 2-hour rolling average of SO_2 emissions calculated using data from the CEM equipment required by 40 CFR part 75 which exceeds the lb/MMBtu limit established in this permit using valid data. Valid data shall meet the requirements of WAQSR, Chapter 5, Section 2(j). The 2-hour average emission rate shall be calculated as the arithmetic average of the previous two (2) operating hours.

7. Any 3-hour block average of SO_2 emissions calculated using data from the CEM equipment required by 40 CFR part 75 which exceeds the lb/hr limit established in this permit using valid data. Valid data shall meet the requirements of WAQSR, Chapter 5, Section 2(j). The 3-hour average emission rate shall be calculated at the end of each 3-hour operating block as the arithmetic average of hourly emissions with valid data during the previous three (3) operating hours.

ii. PacifiCorp will comply with all reporting and record keeping requirements as specified in WAQSR, Chapter 5, Section 2(g).

iii. Exclusion of startup, shutdown, and malfunction emissions only applies to federal standard(s) as authorized in the respective subpart and as authorized in this permit.

14. Effective April 1, 2015, Naughton Unit 3's hourly heat input shall be limited to 3,145 MMBtu/hr, based on a 24-hour block average defined as any 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time at the steam generating unit. Compliance with the heat input limit will be determined using a 40 CFR Part 75 certified CEMS and the procedures for determining heat input per 40 CFR Part 75.

15. Effective January 1, 2018, Naughton Unit 3's heat input shall be limited to 12,964,800 MMBtu based on 12-month rolling average of hourly heat input values. Compliance with the heat input limited will be determined using a 40 CFR Part 75 certified CEMS and the procedures for determining heat input per 40 CFR Part 75.

16. Effective upon permit issuance, this condition shall supersede Condition 5.ii of Air Quality Permit MD-11754.

ii. PAL limits effective upon completion of initial performance tests required by Condition 11.

1. NO_x: 5,402.4 tons per year
   a. Limit is based on a 12-month rolling total.
   b. Initial compliance shall be determined 12 months after the effective date of the PAL. The effective date is the first day of the next month following completion of the initial performance tests required after the completion of natural gas conversion and startup of Unit 3. PacifiCorp Energy shall continue to demonstrate compliance with the NO_x PAL of 11,112.8 tons per year until the initial compliance date for the modified NO_x PAL is triggered.

2. SO_2: 2,862.2 tons per year
   a. Limit is based on a 12-month rolling total.
   b. Initial compliance shall be determined 12 months after the effective date of the PAL. The effective date is the first day of the next month following completion of the initial performance tests required after the completion of natural gas conversion and startup of Unit 3 and. PacifiCorp Energy shall continue to demonstrate compliance with the SO_2 PAL of 8,789.8 tons per year until the initial compliance date for the modified SO_2 PAL is triggered.

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17. Unit 3 shall be equipped with in-stack continuous emission monitoring (CEM) equipment to monitor CO emissions:

i. CO CEM shall be installed and certified within ninety (90) days of permit issuance.

ii. PacifiCorp Energy shall install, calibrate, operate, and maintain a monitoring system, and record the output, for measuring CO emissions discharged to the atmosphere in units of ppm_v, lb/MMBtu, and lb/hr. The CO monitoring system shall consist of the following:

   1. A continuous emission CO monitor located in the stack of Unit 3.

   2. A continuous flow monitoring system for measuring the flow of exhaust gases discharged into the atmosphere.

   3. An in-stack oxygen or carbon dioxide monitor for measuring oxygen or carbon dioxide content of the flue gas at the location CO emissions are monitored.

iii. Each continuous monitor system listed in this condition shall comply with the following:

   1. Monitoring requirements of WAQSR, Chapter 5, Section 2(j) including the following:

      a. 40 CFR part 60, appendix B, Performance Specification 4 or 4a for carbon monoxide. The monitoring systems must demonstrate linearity using 40 CFR part 60, appendix F, and be certified in concentration (ppm_v) and units of lb/MMBtu and lb/hr.

      b. Quality Assurance requirements of 40 CFR part 60, appendix F.

      c. PacifiCorp Energy shall develop and submit for the Division's approval a Quality Assurance plan for each monitoring system listed in this condition. Quality Assurance plans shall be submitted within 180 days from startup of each unit after new low NO_x burners have been installed.

iv. The CO monitor may be removed after December 31, 2017, upon Division approval.

18. Annually, as otherwise specified by the Administrator, Unit 3 shall be tested to verify compliance with the PM limits set forth in Condition 6. The first annual test is required the following calendar year after completion of the initial performance test required by Condition 10. Testing for PM shall be conducted in accordance with EPA Reference Methods 1-5 and 202, or an equivalent EPA Reference Method. A test protocol shall be submitted to this office for review and approval prior to testing. Notification of the test date shall be provided to the Division fifteen (15) days prior to testing. Results of the tests shall be submitted to the Division within forty-five (45) days of completing the tests.

19. Records required by this permit shall be maintained for a period of at least five (5) years and shall be made available to the Division upon request.

20. PacifiCorp Energy shall remove the coal pulverizers on Unit 3 from service no later than January 1, 2018. PacifiCorp Energy shall provide written notification to the Division of the actual date of pulverizer removal within 30 days of such date.

21. PacifiCorp Energy shall complete the conversion of Naughton Unit 3 to natural gas prior to June 30, 2018, and conduct the initial performance tests required in Condition 11 of this permit no later than 90 calendar days after initial startup of Unit 3 after natural gas conversion.

22. This condition shall become effective upon start-up of Naughton Unit 3 after conversion to natural gas, as reported in accordance with Condition 5 of this permit, and shall supersede Air Quality Permit MD-11894 for the Naughton Plant.

23. All conditions from previously issued Air Quality Permits MD-5156, MD-9861, and MD-11725 shall remain in effect unless specifically superseded by a condition of this permit.

It must be noted that this approval does not relieve you of your obligation to comply with all applicable county, state, and federal standards, regulations or ordinances. Special attention must be given to Chapter 6, Section 2 of the Wyoming Air Quality Standards and Regulations, which details the requirements for compliance with Conditions 5, 10 and 11. Attention must be given to Chapter 6, Section 3 of the Wyoming Air Quality Standards and Regulations, which details the requirements for compliance with Condition 3. Any appeal of this permit as a final action of the Department must be made to the Environmental Quality Council within sixty (60) days of permit issuance per Section 16, Chapter I, General Rules of Practice and Procedure, Department of Environmental Quality.

If we may be of further assistance to you, please feel free to contact this office.

Sincerely,

Steven A. Dietrich

Steven A. Dietrich
Administrator
Air Quality Division

Todd Parfitt
Director
Dept. of Environmental Quality

cc: Greg Meeker